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SECTION 18

POWER DISTRIBUTION

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18.1 DISTRIBUTION DEFINED

Broadly speaking, *distribution* includes all parts of an electric utility system between bulk power sources and the consumers' service-entrance equipments. Some electric utility distribution engineers, however, use a more limited definition of distribution as that portion of the utility system between the distribution substations and the consumers' service-entrance equipment. In general, a typical distribution system consists of (1) subtransmission circuits with voltage ratings usually between 12.47 and 345 kV which deliver energy to the distribution substations, (2) distribution substations which convert the energy to a lower *primary system* voltage for local distribution and usually include facilities for voltage regulation of the primary voltage, (3) primary circuits or *feeders*, usually operating in the range of 4.16 to 34.5 kV and supplying the load in a well-defined geographic area, (4) distribution transformers in ratings from 10 to 2500 kVA which may be installed on poles or grade-level pads or in underground vaults near the consumers and transform the primary voltages to utilization voltages, (5) secondary circuits at utilization voltage which carry the energy from the distribution transformer along the street or rear-lot lines, and (6) service drops which deliver the energy from the secondary to the user's service-entrance equipment. Figures 18-1 and 18-2 depict the component parts of a typical distribution system.

Distribution investment constitutes 50% of the capital investment of a typical electric utility system. Recent trends away from generation expansion at many utilities have put increased emphasis on distribution system development.

The function of distribution is to receive electric power from large, bulk sources and to distribute it to consumers at voltage levels and with degrees of reliability that are appropriate to the various types of users.

For single-phase residential users, American National Standard Institute (ANSI) C84.1-1989 defines *Voltage Range A* as 114/228 V to 126/252 V at the user's service entrance and 110/220 V to 126/252 V at the point of utilization. This allows for voltage drop in the consumer's system. Nominal voltage is 120/240 V. Within Range A utilization voltage, utilization equipment is designed and rated to give fully satisfactory performance.

As a practical matter, voltages above and below Range A do occur occasionally; however, ANSI C84.1 specifies that these conditions shall be limited in extent, frequency, and duration. When they do occur, corrective measures shall be undertaken within a reasonable time to improve voltages to meet Range A requirements.

Rapid dips in voltage which cause incandescent-lamp "flicker" should be limited to 4% or 6% when they occur infrequently and 3% or 4% when they occur several times per hour. Frequent dips, such as those caused by elevators and industrial equipment, should be limited to 1½% or 2%.

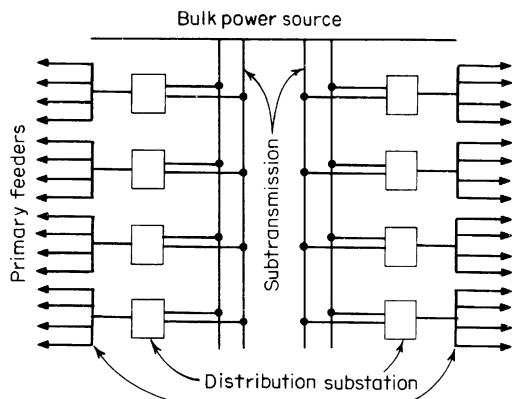
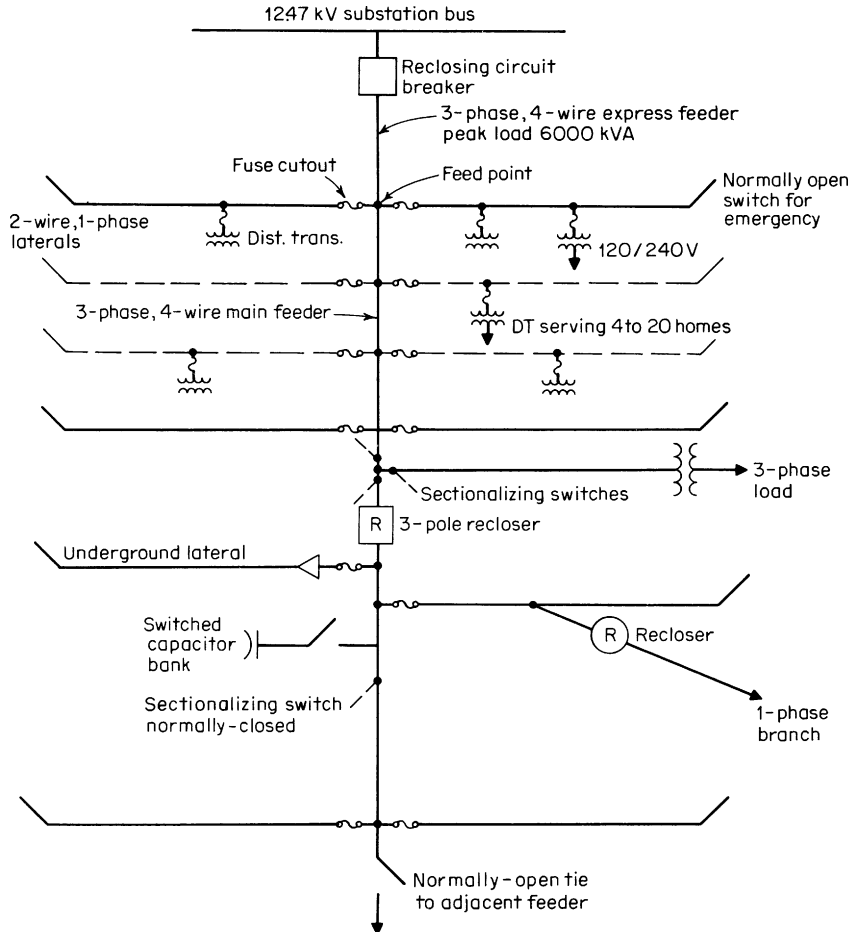


FIGURE 18-1 Typical distribution system.



Residential area: Approx. 1,000 homes/mi²
 Feeder area: 1–4 mi² depending on load density
 15–30 single phase laterals per feeder
 150–500 MVA short-circuit available at substation bus

FIGURE 18-2 One-line diagram of typical primary distribution feeder.

Reliability of service can be described by factors such as frequency and duration of service interruptions. While short and infrequent interruptions may be tolerated by residential and small commercial users, even a short interruption can be costly in the case of many industrial processes and can be dangerous in the case of hospitals and public buildings. For such sensitive loads, special measures are often taken to ensure an especially high level of reliability, such as redundancy in supply circuits and/or supply equipment. Certain computer loads may be sensitive not only to interruptions but even to severe voltage dips and may require special power-supply systems which are virtually uninterruptible.

From a system-planning and design point of view, the optimal choice of subtransmission voltage and system arrangement is closely interrelated with distribution substation size and with the primary distribution voltage level. At any given time, the most economical arrangement is achieved when the sum of the subtransmission, substation, and primary feeder costs to serve an area is a minimum over

the life of the facilities. In practice, the number, size, and availability of bulk supply sources for feeding the subtransmission may be significant factors as well.

A distribution system should be designed so that anticipated load growth can be served at minimum expense. This flexibility is needed to handle load growth in existing areas as well as load growth in new areas of development.

Overhead and underground distribution systems are both used in large metropolitan areas. In the past in smaller towns and in the less-congested areas of larger cities, overhead distribution was almost universally used; the cost of underground distribution for residential areas was several times that of overhead. During the past 25 to 30 years, the cost of underground residential distribution (URD) has been reduced drastically through the development of low-cost, solid-dielectric cables suitable for direct burial, mass production of pad-mounted distribution transformers and accessories, mechanized cable-installation methods, etc. The cost of a typical URD system for a new residential subdivision is about 50% greater than that of an overhead system in many areas; in others, there is little or no differential due to local land conditions. As a result, some utilities will justifiably have some type of extra charge for underground. With the increased public interest in improving the appearance of residential areas and the declining cost of URD, the growth of URD has been extremely rapid. Today, perhaps as much as 70% of new residential construction is served underground. A number of states have enacted legislation making underground distribution mandatory for new residential subdivisions.

Undergrounding*. In the last decade, U.S. East Coast and Midwest regions experienced several catastrophic “100 year storms.” These storms left widespread electric power outages that lasted several days. Given the critical role that electricity plays in our modern lifestyle, even a momentary power outage is an inconvenience. A days-long power outage presents a major hardship and can be catastrophic in terms of its health and safety consequences, and the economic losses it creates. Why then, don’t we bury more of our power lines so they will be protected from storms?

The fact is we already are placing significant numbers of power lines underground. Over the past 10 years, approximately half of the capital expenditures by U.S. investor-owned utilities for new transmission and distribution wires have been for underground wires. Almost 80% of the nation’s electric grid, however, has been built with overhead power lines. Would electric reliability be improved if more of these existing overhead lines were placed underground as well?

What the report finds is that burying existing overhead power lines does not completely protect consumers from storm-related power outages. However, underground power lines do result in fewer overall power outages, but the duration of power outages on underground systems tends to be longer than for overhead lines. Also, undergrounding is expensive, costing up to \$1 million/mile or almost 10 times the cost of a new overhead power line. This means that most undergrounding projects cannot be economically justified and must cite intangible, unquantifiable benefits such as improved community or neighborhood aesthetics for their justification. Determining who pays and who benefits from undergrounding projects can be difficult and often requires the establishment of separate government-sponsored programs for funding.

How Much Does Undergrounding Improve Electric Reliability? Comparative reliability data indicate that the frequency of outages on underground systems can be substantially less than for overhead systems. However, when the duration of outages is compared, underground systems lose much of their advantage. The data show that the frequency of power outages on underground systems is only about one-third of that of overhead systems. A 2000 report issued by the Maryland Public Service Commission concluded that the impact of undergrounding on reliability was “unclear.”

In a 2003 study, the North Carolina Commission summarized 5 years of underground and overhead reliability comparisons for North Carolina’s investor-owned electric utilities—Dominion North Carolina Power, Duke Energy, and Progress Energy Carolinas. The data indicate that the frequency of outages on underground systems was 50% less than for overhead systems, but the average duration of an underground outage was 58% longer than for an overhead outage. In other words, for

*From “Out of Sight, Out of Mind?,” January 2004, Edison Electric Institute (used with permission).

the North Carolina utilities, an underground system suffers only about half the number of outages of an overhead system, but those outages take 1.6 times longer to repair. Based on this data, Duke Power concluded, “Underground distribution lines will improve the potential for reduced outage interruption during normal weather, and limit the extent of damage to the electrical distribution system from severe weather-related storms.” However, once an interruption has occurred, underground outages normally take significantly longer to repair than a similar overhead outage.

Reliability Characteristics of Overhead and Underground Power Lines

- Overhead lines tend to have more power outages primarily due to trees coming in contact with overhead lines.
- It is relatively easy to locate a fault on an overhead line and repair it. A single line worker, for example, can locate and replace a blown fuse. This results in shorter duration outages.
- Underground lines require specialized equipment and crews to locate a fault, a separate crew with heavy equipment to dig up a line, and a specialized crew to repair the fault. This greatly increases the cost and the time to repair a fault on an underground system.
- In urban areas, underground lines are 4 times more costly to maintain than overhead facilities.
- Underground lines have a higher failure rate initially due to dig-ins and installation problems. After 3 or 4 years, however, events that affect failures become virtually nonexistent.
- As underground cables approach their end of life, failure rates increase significantly and these failures are extremely difficult to locate and repair. Maryland utilities report that their underground cables are becoming unreliable after 15 to 20 years and reaching their end of life after 25 to 35 years.
- Pepco found that customers served by 40-year-old overhead lines had better reliability than customers served by 20-year-old underground lines.
- Two Maryland utilities have replaced underground distribution systems with overhead systems to improve reliability.
- Water and moisture infiltration can cause significant failures in underground systems when they are flooded, as often happens in hurricanes.
- Due to cost or technical considerations, it is unlikely that 100% of the circuit from the substation to the customer can be placed entirely underground. This leaves the circuit vulnerable to the same types of events that impact other overhead lines, for example, high winds and ice storms.

Other Benefits of Undergrounding. One of the most commonly cited benefits of undergrounding is the removal of unsightly poles and wires. Local communities and neighborhoods routinely spend millions to place their existing overhead power lines underground.

Similarly, when given the option, builders of new residential communities will often pay a premium of several thousand dollars/home to place the utilities underground. These “aesthetic” benefits are virtually impossible to quantify, but are, in many instances, the primary justification for projects to place existing power lines underground.

Underground lines do have other benefits. In 1998, Australia completed a major benefit/cost analysis of undergrounding all existing power lines in urban and suburban areas throughout the country. The study costed more than \$1.5 million Australian (\$1.05 million U.S. at current rates), and represents what may be the most comprehensive undertaking to date to quantify the benefits and costs related to undergrounding.

In addition to the value of improved aesthetics, the study identified the following potential benefits related to undergrounding that it attempted to quantify:

- Reduced motor vehicle accidents caused by collisions with poles
- Reduced losses caused by electricity outages
- Reduced network maintenance costs
- Reduced tree-pruning costs

- Increased property values
- Reduced transmission losses due to the use of larger conductors
- Reduced greenhouse-gas emissions (lower transmission losses)
- Reduced electrocutions
- Reduced brushfire risks, and
- Indirect effects on the economy such as employment

Of this list, the only four items deemed significant in the study's benefit/cost calculations included:

- Motor vehicle accidents
- Maintenance costs
- Tree-trimming costs, and
- Line losses

The Australian list of benefits does not include improved reliability as a significant benefit of undergrounding. Instead it identifies the reduction in losses from motor vehicle accidents as the largest benefit from undergrounding—something utilities have no control over.

Underground cost data for U.S. utilities indicate that the cost of placing overhead power lines underground is 5 to 10 times the cost of new overhead power lines. Other factors also can result in substantial additional customer costs for undergrounding projects. These include:

- Electric undergrounding strands other utilities, for example, cable and telephone companies, which must assume 100% of pole costs if electric lines are underground. These additional nonelectric costs will likely be passed on to cable and telephone consumers.
- Customers may incur substantial additional costs to connect homes to newly installed underground service, possibly as much as \$2000 if the household electric service must be upgraded to conform to current electric codes.

Paying for Undergrounding. In spite of its high cost and lack of economic justification, undergrounding is very popular across the country. In 9 out of 10 new subdivisions, contractors bury power lines. In addition, dozens of cities have developed comprehensive plans to bury or relocate utility lines to improve aesthetics.

For new residential construction, utilities vary on how they charge for the cost of providing underground services. When it comes to converting existing overhead lines to underground, a variety of programs are being utilized. They include special assessment areas, undergrounding districts, and state and local government initiatives.

Placing existing power lines underground is expensive, costing approximately \$1 million/mile. This is almost 10 times the cost of a new overhead power line.

While communities and individuals continue to push for undergrounding—particularly after extended power outages caused by major storms—the reliability benefits that would result are uncertain, and there appears to be little economic justification for paying the required premiums.

Indeed, in its study of the undergrounding issue, the Maryland Public Service Commission concluded, “If a 10 percent return is imputed to the great amounts of capital freed up by building overhead instead of underground lines, the earnings alone will pay for substantial ongoing overhead maintenance,” implying that utilities could have more resources available to them to perform maintenance and improve reliability on overhead lines if they invested less in new underground facilities.

For the foreseeable future, however, it appears that the undergrounding of existing overhead power lines will continue, justified primarily by aesthetic considerations—not reliability or economic benefits. Many consumers simply want their power lines placed underground, regardless of the costs. The challenge for decision makers is determining who will pay for these projects and who will benefit.

There are several undergrounding programs around the country that are working through these equity issues and coming up with what appear to be viable compromises. Once a public-policy

decision is reached to pursue an undergrounding project, it is worthwhile for the leaders involved to evaluate these programs in more detail to determine what is working, and what is not.

Rural Service. Rural service has been extended to most farmers and rural dwellers through the efforts of utilities, cooperatives, and government agencies. Rural construction must be of the least-expensive type consistent with durability and reliability because there may be only a few users per mile of line. Historically, rural construction has been overhead, but the advent of cable-plowing techniques has made underground economically competitive with overhead in some parts of the country, and a growing amount of rural distribution is being installed underground.

Higher primary voltages of 24.9Y/14.4 and 34.5Y/19.92 kV are continuing to grow in usage, although primary voltages in the 15-kV class predominate. The 5-kV class continues to decline in usage. Surveys indicate that in recent years approximately 78% of the overhead and underground line additions are at 15 kV, 11% are at 25 kV, and 7.5% are at 35 kV.

Generally, when a higher distribution voltage is initiated, it is built in new, rapidly growing load areas. The economic advantage of the higher voltages usually is not great enough to justify massive conversions of existing lower-voltage facilities to the higher level. The lower-voltage areas are contained and gradually compressed over a period of years as determined by economics, obsolescence, and convenience. Virtually, all modern primary systems serving residential and small commercial and small industrial loads are 4-wire, multigrounded, common-neutral systems.

18.2 DISTRIBUTION-SYSTEM AUTOMATION

Distribution automation (DA), a system to monitor and control the distribution system in real-time, was gradually introduced in the 1970s more as a concept than a fully developed plan. Unlike the introduction of EMS, where utilities readily saw the benefits of automatic generation control and economic dispatch and adopted the technology, utilities were much more cautious in their approach to distribution automation.

Early distribution automation projects were undertaken by a handful of utilities. The technology was changing and evolving so much so that DA was being touted as an amorphous system capable of covering any imaginable function under the sun. A 1984 EPRI project, *Guidelines for Evaluating Distribution Automation*, focused attention on what functions could be automated and what value could be attached to those functions. A positive result of this project is that it got people thinking about what functions mattered most. However, it was a little bit ahead of its time in that there wasn't much standardization in systems employed for DA and one couldn't simply select functions of interest and expect to obtain a system that could be built for the total value of the functions selected. Then too, the choice of the communications systems (e.g., telephone, fiber optics, radio, carrier, etc.) proved to be a barrier to widespread implementation.

At the substation level, equipment loadings became an early focus, and asset management became a desired function for DA systems. In addition, the ability to trip distribution circuit breakers and transfer load between substations was commonplace as SCADA was added and this represented the extent of distribution automation to many companies.

Volt/var control, that is, controlling the combination of load tap changers (LTC) or voltage regulators and switched capacitor banks within a substation, was a function many companies incorporated with DA. With adoption of microprocessor relays and fault distance relaying, some incorporated the output information from fault distance relays and diagnostic alarms from various subsystems to be part of the DA package.

Moving outside the substation, controlling automated circuit tie switches was prompted by reliability considerations. Having SCADA links to other reclosers, particularly the ones with microprocessor controls, enabled more ability to remotely control field switching and achieve more rapid restoration of service.

Distribution automation is still evolving with systems incorporating many of the functions previously described. More utilities are employing varying degrees of distribution automation and more standardization is taking place.

18.3 CLASSIFICATION AND APPLICATION OF DISTRIBUTION SYSTEMS

Distribution systems may be classified in according to:

- voltage—120 V, 12,470 V, 34,500 V, etc.
- scheme of connection—radial, loop, network, multiple, and series.
- loads—residential, small light and power, large light and power, street lighting, railways, etc.
- number of conductors—2-wire, 3-wire, 4-wire, etc.
- type of construction—overhead or underground.
- number of phases—single-phase, 2-phase, or 3-phase; and as to frequency: 25 Hz, 60 Hz, etc.

Application of Systems. In American practice, alternating-current (ac) 60-Hz systems are almost universally used for electric power distribution. These systems comprise the most economical method of power distribution, owing in large measure to the ease of transforming voltages to levels appropriate to the various parts of the system. These transformations are accomplished by means of reliable and economical transformers. By proper system design and the application of overvoltage and overcurrent protective equipment, voltage levels and service reliability can be matched to almost any consumer requirement.

Single-phase residential loads generally are supplied by simple radial systems at 120/240 V. The ultimate in service reliability is provided in densely loaded business/commercial areas by means of grid-type secondary-network systems at 208Y/120 V or by “spot” networks, usually at 480Y/277 V. Secondary-network systems are used in about 90% of the cities in this country having a population of 100,000 or more and in more than one-third of all cities with populations between 25,000 and 100,000.

Where secondary-network systems do not supply sufficiently reliable service for critical loads, emergency generators and/or batteries are sometimes provided together with automatic switching equipment so that service can be maintained to the critical loads in the event that the normal utility supply is interrupted. Such loads are found in hospitals, computer centers, key industrial processes, etc.

Single-phase residential loads are almost universally supplied through 120/240-V, 3-wire, single-phase services. Large appliances, such as ranges, water heaters, and clothes dryers, are served at 240 V. Lighting, small appliances, and convenience outlets are supplied at 120 V.

An exception to the preceding comments occurs when the dwelling unit is in a distributed secondary-network area served at 280Y/120 V. In this case, large appliances are supplied at 208 V and small appliances at 120 V.

Three-phase, 4-wire, multigrounded, common-neutral primary systems, such as 12.47Y/7.2 kV, 24.9Y/14.4 kV, and 34.5Y/19.92 kV, are used almost exclusively. The fourth wire of these Y-connected systems is the neutral for both the primary and the secondary systems. It is grounded at many locations. Single-phase loads are served by distribution transformers, the primary windings of which are connected between a phase conductor and the neutral. Three-phase loads can be supplied by 3-phase distribution transformers or by single-phase transformers connected to form a 3-phase bank. Primary systems in the 15-kV class are most commonly used, but the higher voltages are gaining acceptance. Figure 18-2 illustrates a typical radial primary feeder.

The 4-wire system is particularly economic for URD systems because each primary lateral or branch circuit consists of only one insulated phase conductor and the bare, uninsulated neutral rather than two insulated conductors. Also, only one primary fuse is required at each transformer and one surge arrester in overhead installations.

Three-phase, 3-wire primary systems are not widely used for public distribution, except in California. They can be used to supply single-phase loads by means of distribution transformers having primary winding connected between two phase conductors. Single-phase primary laterals consist of two insulated phase conductors; each single-phase distribution transformer requires two fuses and two surge arresters (where used). Three-phase loads are served through 3-phase distribution transformers or appropriate 3-phase banks. Two-phase systems are rarely used today.

18.4 CALCULATION OF VOLTAGE REGULATION AND I^2R LOSS

When a circuit supplies current to a load, it experiences a drop in voltage and a dissipation of energy in the form of heat. In dc circuits, voltage drop is equal to current in amperes multiplied by the resistance of the conductors, $V = IR$. In ac circuits, voltage drop is a function of load current and power factor and the resistance and reactance of the conductors. Heating is caused by conductor losses; for both dc and ac circuits they are computed as the square of current multiplied by conductor resistance in ohms. Watts = I^2R , or kW = $I^2R/1000$. Capacitance can usually be neglected for calculation in distribution circuits because its effect on voltage drop is negligible for the circuit lengths and operating voltages used. In circuit design, a conductor size should be selected so that it will carry the required load within specified voltage-drop limits and will have an optimized value of installed cost and cost of losses. Today, a conductor size meeting these criteria will operate well within safe operating temperature limits. In some cases, short-circuit current requirements will dictate the minimum conductor size.

Percent voltage drop or percent regulation is the ratio of voltage drop in a circuit to voltage delivered by the circuit, multiplied by 100 to convert to percent. For example, if the drop between a transformer and the last customer is 10 V and the voltage delivered to the customer is 240, the percent voltage drop is $10/240 \times 100 = 4.17\%$. Often the nominal or rated voltage is used as the denominator because the exact value of delivered voltage is seldom known.

Percent I^2R or percent conductor loss of a circuit is the ratio of the circuit I^2R or conductor loss, in kilowatts, to the kilowatts delivered by the circuit (multiplied by 100 to convert to percent). For example, assume a 240-V single-phase circuit consisting of 1000 ft of two No. 4/0 copper cables supplies a load of 100 A at unity power factor.

$$I^2R = 100^2 \times 2 \times 0.0512 = 1024 \text{ W} = 1.024 \text{ kW}$$

$$\text{Load delivered} = 240 \times 100 = 24,000 \text{ W} = 24 \text{ kW}$$

$$\% I^2R \text{ loss} = 1.024/24 \times 100 = 4.26\%$$

Direct-current voltage drop is easily calculated by multiplying load amperes I by ohmic resistance R of the conductors through which the current flows (see Sec. 4 for ohmic resistance of various conductors).

Example: A 500-ft dc circuit of two 4/0 copper cables carries 200 A. What is the voltage drop? Resistance of 1000 ft of 4/0 copper cable is 0.0512 Ω .

$$\text{Drop} = IR = 200 \times 0.0512 = 10.24 \text{ V}$$

If 240 is the delivered voltage,

$$\% \text{ regulation} = 10.24/240 \times 100 = 4.26\%$$

I^2R or conductor loss in dc or ac circuits is calculated by multiplying the square of the current in amperes by ohmic resistance of the conductors through which the current flows. The result is in watts.

In dc circuits, percent voltage drop and percent conductor loss are identical.

$$\% \text{ voltage drop} = IR/V \times 100$$

$$\% I^2R = I^2R/VI \times 100 = IR/V \times 100$$

In ac circuits, the ratio of percent conductor loss to percent voltage regulation is given approximately by the following approximate formula:

$$\frac{\% I^2R \text{ loss}}{\% \text{ voltage drop}} = \frac{\cos \phi}{\cos \theta \cos (\phi - \theta)} \quad (18-1)$$

where θ = power-factor angle and ϕ = impedance angle; that is, $\tan \phi = X/R$.

TABLE 18-1 Voltage Drop in Volts per 100,000 A · ft, 2-Wire DC Circuits (Loop)

Conductor size, AWG or kcmil		Volts drop per 100,000 A · ft, 90° copper temp
Copper	Approx. equivalent aluminum	
6	4	102.8
4	2	64.6
2	1/0	40.7
1/0	3/0	25.6
2/0	4/0	20.3
4/0	336	12.8
350	556	7.71
500	795	5.39
1000		2.70
1500		1.80
2000		1.35

Note: 1 ft = 0.3048 m.

Table 18-1 gives voltage drop in volts per 100,000 A · ft for 2-wire dc circuits for a number of conductor sizes. Ampere-feet is the product of the number of amperes of current flowing and the distance in feet between the sending and receiving terminals multiplied by 2 to take into account the drop in both the outgoing and return conductors. Or the feet can be considered to be the total number of conductor feet, outgoing and return.

Table 18-1 also gives the voltage drop for 3-wire circuits when serving balanced loads, where the term “feet” is taken to mean twice the number of feet between sending and receiving terminals.

Example 1. What is the voltage drop and percent voltage drop when 200 A dc flows 1500 ft one way through a 2-wire, 120-V, 556-kcmil aluminum circuit? First determine ampere-feet factor as $100 \times 1500/100,000 = 1.5$. From Table 18-1, the voltage drop is 7.71 V per 100,000 A · ft. This value multiplied by the 1.5 factor gives the total voltage drop = $1.5 \times 7.71 = 11.6$ V. The percent voltage drop = $11.6 \times 100/120 = 9.64\%$. The percent conductor loss also is 9.64%, which is equivalent to $120 \times 100 \times 0.0954 = 1.16$ kW.

Example 2. A mine 1 mile from a motor-generator station must receive 100 kW dc at not less than 575 V. Maximum voltage of the generator is 600 V. What conductor size should be used?

$$\text{Max. current} = \frac{100,000 \text{ W}}{575 \text{ V}} = 173.9 \text{ A}$$

$$\text{Loop ft} = 2 \times 5280 = 10,560 \text{ ft}$$

$$\frac{\text{A} \cdot \text{ft}}{100,000} = \frac{173.9 \times 10,560}{100,000} = 18.36$$

$$18.36 \times \text{voltage drop per } 100,000 \text{ A} \cdot \text{ft from Table 18-1} = 25 \text{ V}$$

Therefore, voltage drop per 100,000 A · ft = $25/18.36 = 1.36$. From Table 18-1, the copper conductor size corresponding to 1.36 V/100,000 A · ft is 2000 kcmil copper.

Calculating Voltage Drop in AC Circuits. The voltage drop per mile in each round wire of 3-phase 60-Hz line with equilateral spacing D inches between centers or in each wire of a single-phase line D inches between centers is

$$\tilde{V}_{\text{drop}} = \tilde{I}R + j\tilde{I}\left(0.2794 \log \frac{D}{r} + 0.03034 \mu\right) \quad \text{volts in phasor form} \quad (18-2)$$

where $\tilde{I}$ is in phasor amperes, R is the 60-Hz resistance of the wire per mile, Ω , $\log$ is the log to base 10, r is the radius of round wire, in, and μ is the permeability of the wire (unity for nonmagnetic materials such as copper or aluminum). j in Eq. (18-2) denotes an angle of 90° ; $+j$ means 90° leading, $-j$ means 90° lagging. Thus, the expression for phasor current lagging the reference voltage is $I = I_x - jI_y = I\sqrt{\theta^\circ}$ with reference to a conveniently chosen horizontal axis of reference—usually sending- or receiving-end voltage. The symbol $\sim$ over I or V indicates phasor values. Voltage drops determined in this manner are also phasors and are with respect to the reference axis.

When wire is stranded, an equivalent radius must be used for r in Eq. (18-2). $r = 0.528 \sqrt{A}$ for 7 strands, $r = 0.5585 \sqrt{A}$ for 19 strands, $r = 0.5675 \sqrt{A}$ for 37 strands, where r = equivalent radius, in, and A = area of metal, in².

Frequency is 60 Hz for the constants in parentheses in Eq. (18-2), which gives reactance X in ohms per mile. For 25 Hz, multiply by 25/60. The equation is sometimes written

$$\tilde{V} \text{ drop per mile} = \tilde{I} (R + jX) = \tilde{I} \tilde{Z} \quad \text{volts in phasor form} \quad (18-3)$$

where I is in phasor amperes and $Z = Z/\phi \cdot \Omega/\text{mi}$ at 60 Hz.

Three unsymmetrically spaced wires a , b , and c of a 3-phase circuit with correct transpositions can have voltage drop in each wire calculated by Eq. (18-2) by substituting for D the geometric mean of the three interaxial distances:

$$D = \sqrt[3]{D_{ab} D_{bc} D_{ca}}$$

The Phasor Method. In Eq. (18-3), I is in vector amperes,

$$\tilde{I} = I_x - jI_y = I\angle\theta$$

where θ is the angle that the current lags (or leads) the voltage. The sending-end voltage is usually chosen as the axis, or phasor, of reference in drawing the phasor diagram. For example, consider Fig. 18-3, where sending voltage $V_s = V_s\angle\theta^\circ$, load current $I = I\angle\theta^\circ$, circuit impedance $\tilde{Z} = Z/\theta^\circ = R + jX$, and load voltage $\tilde{V}_L = \tilde{V}_s - \tilde{I} \tilde{Z}$ (all phasors). The symbol $\angle$ is used for positive angles, assuming that the counterclockwise direction from the phasor or reference is positive and the clockwise directions negative. Assume that $V_s = 230\angle 0^\circ$, $\tilde{I} = 50\angle -36.87^\circ$, $\tilde{Z} = 0.2\angle 71.57^\circ$, and $\tilde{Z} = R + jX$. Thus

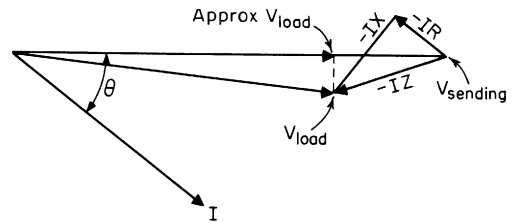


FIGURE 18-3 Phasor diagram showing voltage relationships.

Assume that $V_s = 230\angle 0^\circ$, $\tilde{I} = 50\angle -36.87^\circ$, $\tilde{Z} = 0.2\angle 71.57^\circ$, and $\tilde{Z} = R + jX$. Thus

$$\begin{aligned} \tilde{V}_L &= 230\angle 0^\circ - 50\angle -36.87^\circ \times 0.2\angle 71.57^\circ \\ &= 230\angle \theta^\circ - 10\angle 34.70^\circ \\ &= 230 - 10 \cos 34.70^\circ - j 10 \sin 34.70^\circ \\ &= 230 - 8.22 - j 5.69 = 221.78 - j 5.69 \\ &= 221.78 \text{ (very nearly)} \end{aligned}$$

Neglecting the term $-j 5.69$ simplifies the final calculation and gives the load voltage within a fraction of 1% of the precise result. This method is sufficiently accurate for practically all distribution engineering calculations and can be thought of as

$$V \text{ drop} = IR \cos \theta + IX \sin \theta = IZ \cos (\phi - \theta) \quad (18-4)$$

where I and Z are absolute magnitudes, not phasor quantities, ϕ is the impedance angle, and θ is the power-factor angle by which the current lags (or leads) the voltage. Calculating the drop in the above example by this method:

$$\begin{aligned} V \text{ drop} &= 50 \times 0.2 \times \cos 71.57^\circ \times \cos 36.87^\circ \\ &\quad + 50 \times 0.2 \times \sin 71.57^\circ \times \sin 36.87^\circ \\ &= 2.53 + 5.69 = 8.22 \text{ V} \end{aligned}$$

or

$$\begin{aligned} V \text{ drop} &= IZ \cos (\phi - \theta) = 50 \times 0.2 \times \cos (71.57^\circ - 36.87^\circ) \\ &= 10 \cos (34.7^\circ) = 10 \times 0.822 = 8.22 \text{ V} \end{aligned}$$

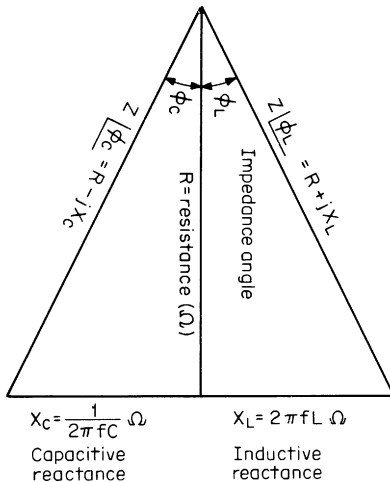


FIGURE 18-4 Impedance diagrams for series connection of resistance and reactance (L = inductance, in henrys; C = capacitance, in farads; F = frequency, in hertz).

Impedance Z can be visualized as the hypotenuse of a right triangle in which the base is the resistance R and the altitude is the reactance X . In phasor form, $\tilde{Z} = R \pm jX$, where the positive sign is used for inductive reactance and the negative sign for capacitive reactance. Impedance also can be expressed as $\tilde{Z} = Z/\phi^\circ$, where Z is the absolute magnitude and ϕ is the angle between $\tilde{Z}$ and R in Fig. 18-4. This angle is an absolute value in that it has no relationship to the axis of reference in a phasor diagram, as do voltage and current. Alternating current causes a voltage drop in resistance which is in time phase with the current and in inductive reactance a drop which leads the current by 90 electrical degrees, assuming the positive direction for measurement of angles is counterclockwise. Or conversely, the current in an inductive reactance lags the voltage drop by 90°.

Impedance Values. Tables are available which give 60-Hz impedance values in ohms per 1000 ft for common sizes of wire and cable. The values can be expressed in the form $\tilde{Z} = R + jX$, which can be converted to the form Z/ϕ° if desired. The latter form is convenient to use in voltage-drop calculations when the current is expressed as I/ϕ° .

Power Factor. In typical distribution loads, the current lags the voltage, as shown in Fig. 18-3, where θ is shown as the angle between current and sending voltage and $\cos \theta$ is referred to as the *power factor* of the circuit. In a purely resistive circuit, the current and voltage are in phase; consequently, the power factor is 1.0 or unity. In a purely inductive circuit, the voltage and current are out of phase by 90 electrical degrees, resulting in a power factor of zero. In a circuit consisting of a resistance in series with a reactance of equal ohmic value ($\phi = 45^\circ$), $\theta = \pm 45^\circ$ also. Thus, the power factor is $\cos 45^\circ = 0.707$, or 70.7%.

In a single-phase ac circuit, the load in kW can be expressed as

$$\text{kW} = EI \cos \theta \quad (18-5)$$

where E = magnitude of rms line-to-neutral voltage, kV

I = magnitude of current, rms amperes

θ = electrical angle between phasor voltage and current

From Eq. (18-5), it is obvious that the magnitude of the current for a given voltage and kilowatt load depends on the power factor, or

$$I = \text{kW}/(E \cos \theta) \quad (18-6)$$

The corresponding equations for balanced 3-phase circuits are

$$\text{kW} = \sqrt{3} EI \cos \theta \quad (18-7)$$

and

$$I = \text{kW}/(\sqrt{3} E \cos \theta) \quad (18-8)$$

where the symbols are as specified above, and θ is measured as the angle between the line-to-neutral voltage of a given phase and the current in that phase.

Example. Given a load of 500 kW at 80% power factor (lagging), 7.2 kV circuit voltage, 60-Hz, single-phase circuit using 1/0 aluminum conductor spaced 30 in on centers. The load is located 1 mi from the substation. What is the voltage drop? From tables on conductor characteristics,

$$r = 0.185 \, \Omega/1000 \text{ ft}$$

$$x = 0.124 \, \Omega/1000 \text{ ft}$$

$$\text{Therefore,} \quad R + jX = 5.28 (0.185 + j 0.124) = 0.9769 + j 0.6547 \, \Omega$$

From Eq. (18-6),

$$I = \frac{\text{kW}}{E \cos \theta} = \frac{500}{7.2 \times 0.8} = 86.81 \text{ A}$$

$$E = 7.2/\theta^\circ$$

$$\cos \theta = 0.80$$

$$\theta = 36.87^\circ$$

and

$$\sin \theta = 0.60$$

From Eq. (18-4),*

$$\begin{aligned} \text{Voltage drop} &= 2(IR \cos \theta + IX \sin \theta) = (86.81 \times 0.9769 \times 0.8 + 86.81 \times 0.6547 \times 0.6) \\ &= 2(67.84 + 34.10) = 203.88 \text{ V} \end{aligned}$$

Calculation of 3-Phase Line Drops with Balanced Loads. In 3-phase circuits with balanced loads on each phase, the line-to-neutral voltage drop is merely the product of the phase current and the conductor impedance as determined from standard tables. There is no return current with balanced 3-phase loads. Thus, the line-to-line voltage drop is $\sqrt{3}$ times the line-to-neutral drop, or

$$V_{\text{drop } L-L} = \sqrt{3}(IR \cos \theta + IX \sin \theta) \quad (18-9)$$

*The factor of 2 is used for a single-phase system to represent the impedance of the outgoing conductor and the return conductor.

For example, assume that the circuit of the preceding example now is a 3-phase 12.47-kV circuit 1 mi long with the same 1/0 aluminum conductors at an equivalent spacing of 30 in and a load of $3 \times 500 = 1500$ kW at 0.8 pf lagging. What is the line-to-line voltage drop? R and X are the same values as previously; that is, $R + jX = 0.9769 + j 0.6547 \Omega$.

The current per phase from Eq. (18-7) is

$$I = \frac{\text{kW}}{\sqrt{3} E \cos \theta} = \frac{1500}{\sqrt{3} \times 12.47 \times 0.8} = 86.81 \text{ A}$$

as before,

$$\begin{aligned} V_{\text{drop } L-L} &= \sqrt{3} (IR \cos \theta + IX \sin \theta) \\ &= \sqrt{3} (86.81 \times 0.9769 \times 0.8 + 86.81 \times 0.6547 \times 0.6) \\ &= 117.51 + 59.06 = 176.57 \text{ V (approx.)} \end{aligned}$$

Calculation of Voltage Drop in Unbalanced Unsymmetrical Circuits. If there are n different wires $a, b, c, d, \dots, n$ carrying currents $I_a, I_b, I_c, \dots, I_n$, respectively, whether 2-, 3-phase, the voltage drop in wire a per mile at 60 Hz is

$$\begin{aligned} I_a R_a + j \left[0.2794 \left(I_a \log \frac{1}{r} + I_b \log \frac{1}{D_{ab}} + I_c \log \frac{1}{D_{ac}} + \dots \right. \right. \\ \left. \left. + I_n \log \frac{1}{D_{an}} \right) + 0.03034 \mu I_a \right] \quad \text{volts in phasor form} \end{aligned} \quad (18-10)$$

where currents are in phasor amperes, R_a is 60-Hz ohmic resistance of conductor a per mile, r is equivalent radius, in inches, of conductor a , D_{ab} , D_{ac} , and D_{an} are distances, in inches, between centers of conductors a and b , a and c , and a and n , and μ is the permeability of conductor a (unity for nonmagnetic material). To get the drop in b , replace all a 's by b 's and all b 's by a 's in Eq. (18-10); similarly, to get the drop in c , interchange a 's and c 's; likewise for n . For 25 Hz, multiply that part of Eq. (18-10) which is in brackets by 25/60. Equation (18-10) gives voltage drop for any degree of load unbalance, power factor, or conductor arrangements. In using this formula, calculations are made easier by choosing voltage to neutral as the reference axis.

Approximate Method of Calculating Voltage Drop in Unbalanced, Unsymmetrical Circuits.

Equation (18-10) requires laborious calculations and is used only when exact results are necessary. Voltage drops sufficiently accurate for engineering purposes can be calculated by using an equivalent impedance for each conductor. The reactance component of the equivalent impedance is computed from a spacing D equal to the geometric means of the interaxial distances of the other conductors to the conductor being considered. For instance, if there are four conductors a, b, c , and n for conductor a , $D = \sqrt[3]{D_{ab} D_{ac} D_{an}}$; for conductor b , $D = \sqrt[3]{D_{ab} D_{bc} D_{bn}}$.

Phasor and Connection Diagrams. Phasor and connection diagrams are drawn in computing voltage drops in unbalanced circuits. Figure 18-5 shows an unbalanced 4-wire 3-phase 4160Y/2400-V circuit with assumed loads, power factors, and equivalent line impedances. Phase-to-neutral drops between source and load are given by the following, using one of the many possible voltage-notation conventions:

$$\begin{aligned} V_{na} - V_{n'a'} &= I_a Z_a + I_n Z_n \\ V_{nb} - V_{n'b'} &= I_b Z_b + I_n Z_n \\ V_{nc} - V_{n'c'} &= I_c Z_c + I_n Z_n \end{aligned} \quad (18-11)$$

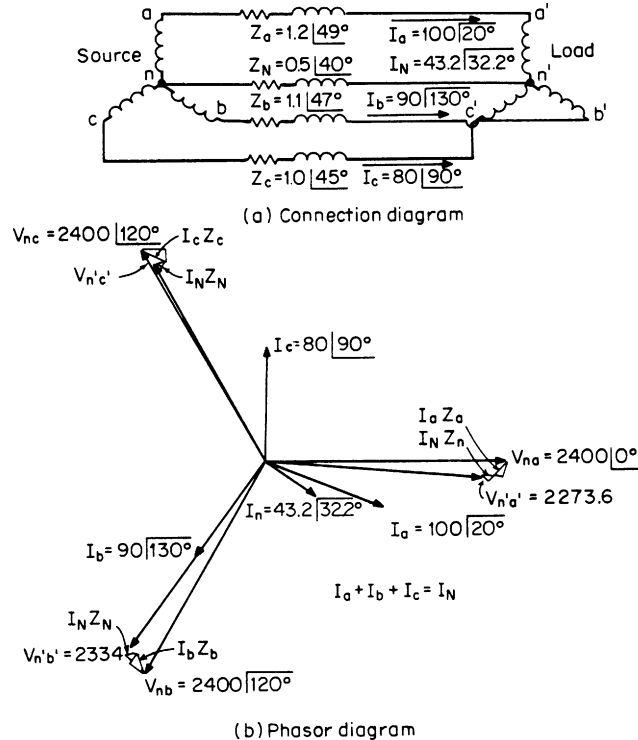


FIGURE 18-5 Connections and phasor diagrams for unbalanced loads and unsymmetrical circuit.

Phase-to-phase drops between source and load are given by the following:

$$\begin{aligned} V_{ba} - V_{b'a'} &= I_a Z_a - I_b Z_b \\ V_{ac} - V_{a'c'} &= I_c Z_c - I_a Z_a \\ V_{cb} - V_{c'b'} &= I_b Z_b - I_c Z_c \end{aligned} \quad (18-12)$$

In computing line-to-neutral drop in phase a , it is convenient to choose V_{na} as the axis of reference.

$$\begin{aligned} V_{na} - V_{n'a'} &= I_a Z_a + I_N Z_N = (100/\underline{20^\circ})(1.2/\underline{49^\circ}) + (43.2/\underline{32.2^\circ})(0.5/\underline{40^\circ}) \\ &= 120/\underline{29^\circ} + 21.6/\underline{7.8^\circ} = 126.4 + j61.9 \end{aligned}$$

$$\text{Load voltage } V_{n'a'} = 2400 - 126.4 - j61.9 = 2273.6 \text{ V (very nearly)}$$

Likewise, in computing line-to-neutral drop in phase b , it is convenient to choose V_{nb} as the axis of reference. The phasor diagram of Fig. 18-5 must be rotated in a counterclockwise direction 120° ; then $I_b = 90/\underline{10^\circ}$ and $I_N = 43.2/\underline{87.8^\circ}$.

$$V_{nb} - V_{n'b'} = I_b Z_b + I_N Z_N = (90/\underline{10^\circ})(1.1/\underline{47^\circ}) + (43.2/\underline{87.8^\circ})(0.5/\underline{40^\circ}) = 65.8 + j76.6$$

$$\text{Load voltage } V_{n'b'} = 2400 - 65.8 - j76.6 = 2334.2 \text{ V (very nearly)}$$

Drop in the neutral conductor of a 4-wire 3-phase circuit or a 3-wire 2-phase circuit makes resultant drop on the more heavily loaded phases greater than it would be for the same current under balanced conditions. Likewise, net drop is less on more lightly loaded phases than for the same current when balanced.

Distributed Loads, Voltage Drop, and I^2R Loss.

Voltage drop and conductor power losses resulting from a concentrated load on a distribution line can be calculated easily as shown in earlier parts of this

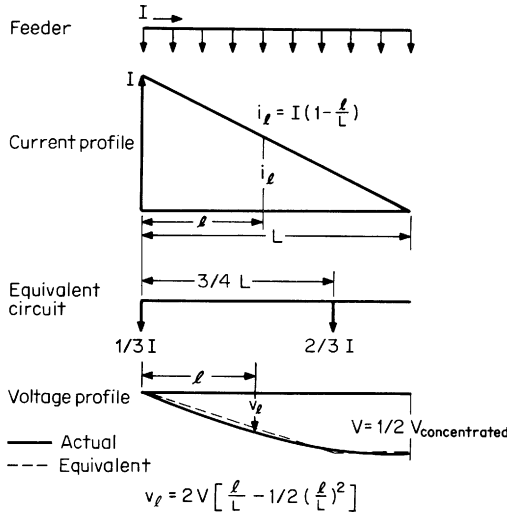


FIGURE 18-6 Uniformly distributed loads.

section. However, distribution circuit loads are generally considered to be distributed—often, but not always, uniformly. Distributed load may be considered as effectively concentrated at one point along the circuit to calculate total voltage drop and at another point to calculate conductor I^2R losses in the conductor. If the load is uniformly distributed along the feeder, the total voltage drop can be calculated by assuming that the entire load is concentrated at the midpoint of the circuit, and the total I^2R losses can be calculated by assuming that the load is concentrated at a point one-third the total distance from the source.

However, if there is a superimposed through load beyond the given feeder section, this method of calculation becomes cumbersome. It is possible to develop a single precise equivalent circuit for both the voltage-drop and loss calculations. Figure 18-6 shows the load representation and equivalent for uniformly distributed loads. Equivalents also can

be developed for other types of distribution. Figure 18-6 shows the equivalent circuit of two-thirds of the total load concentrated at three-quarters of the total distance from the source.

18.5 THE SUBTRANSMISSION SYSTEM

Definition. *Subtransmission* is that part of the utility system which supplies distribution substations from bulk power sources, such as large transmission substations or generating stations. In turn, the distribution substations supply primary distribution systems. Subtransmission has many of the characteristics of both transmission and distribution in that it moves relatively large amounts of power from one point to another, like transmission, and at the same time it provides area coverage, like distribution.

In some utility systems, transmission and subtransmission voltages are identical; in other systems, subtransmission is a separate and distinct voltage level (or levels). This is easy to account for because in the evolutionary development of utility systems, today's transmission voltage naturally tends to become tomorrow's subtransmission voltage, just as today's subtransmission voltage tends to become tomorrow's primary distribution voltage.

Because of the wide range of voltages used in subtransmission, and because of the wide variation in geographic conditions and local ordinances, subtransmission circuits are sometimes built on pole lines on city streets, or on tower lines on private rights-of-way, or in underground cables.

Voltages. Voltages of subtransmission circuits range from 12 to 345 kV, but today the levels of 69, 115, and 138 kV are most common. The use of the higher voltages is expanding rapidly as higher

primary voltages are receiving increased usage. Current practice as indicated by an informal utility survey is shown in Fig. 18-7; 115 and 138 kV together comprise about half the usage, 69 kV about 20%; 230 kV usage is becoming substantial, reflecting the growing use of 25- and 34.5-kV primary distribution.

Conductors of ACSR or aluminum generally have supplanted copper in overhead construction, and aluminum conductors are being used increasingly in cables.

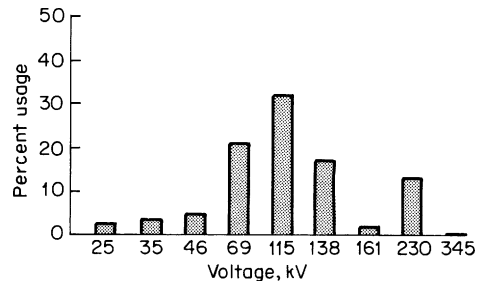


FIGURE 18-7 Use of distribution substation high-voltage rating.

Voltage Regulation of Subtransmission. The size of conductors used in subtransmission systems is determined by (1) magnitude and power factor of the load, (2) emergency loading requirements, (3) distance that the load must be carried, (4) operating voltage, (5) permissible voltage drop under normal and emergency loading, and (6) optimal economic balance between installed cost of the conductor and cost of losses. Table 18-2 gives the line-to-neutral voltage drops per 100,000 A · ft for common cable and overhead conductor sizes and representative power factors for 34.5- and 69-kV subtransmission. Values in the table are based on the approximate formula (18-4)

$$V_{\text{drop}} = IR \cos \theta + IX \sin \theta = IZ \cos (\phi - \theta)$$

where R , X , and Z are 60-Hz resistance, reactance, and impedance in ohms per 1000 ft of a single conductor, θ is the power-factor angle in electrical degrees, and ϕ is the impedance angle, $\tan^{-1} (X/R)$.

Examples of How to Use Table 18-2. Determine the voltage drop when a 3-phase 20,000-kVA load at 95% power factor is carried 10 mi over an overhead 69-kV circuit with No. 2/0 ACSR conductor. Assuming the receiving-end voltage to be 69 kV, the current is

$$I = \frac{\text{kVA}}{\sqrt{3}E} = \frac{20,000}{\sqrt{3} \times 69} = 167.35 \text{ A}$$

Circuit feet are

$$10 \times 5280 = 52,800 \text{ ft}$$

$$\text{Thus } \frac{\text{A} \cdot \text{ft}}{100,000} = \frac{167.35 \times 52,800}{100,000} = 88.36$$

From the overhead portion of Table 18-2, the voltage drop per 100,000 A · ft at 95% power factor for a No. 2/0 ACSR conductor is 19.1 V. Therefore, the total voltage drop for the example is $88.36 \times 19.1 = 1687.68$ V line-to-neutral. Since normal line-to-neutral voltage is $69/\sqrt{3} = 39.838$ kV, or 39,838 V, the percent voltage drop is $1687.68 \times 100/39,838 = 4.24\%$.

Assuming that permissible voltage drop is the limiting factor, what overhead ACSR conductor size should be used to supply a load of 40,000 kVA at 95% power factor and receiving-end voltage of 69 kV with a permissible drop of 5% and 8 mi between sending and receiving ends?

$$\text{Current} = \frac{40,000}{\sqrt{3} \times 69} = 334.71 \text{ A}$$

$$\text{Circuit feet} = 8 \times 5280 = 42,240 \text{ ft}$$

$$\frac{\text{A} \cdot \text{ft}}{100,000} = \frac{334.71 \times 42,240}{100,000} = 141.38$$

TABLE 18-2 Voltage Drops per 100,000 A · ft* for 3-Phase, 60-Hz, 34.5- and 69-kV Subtransmission

Conductor size	Voltage class										Approx. amp. capacity for air moving at 2 ft/s
	34.5 kV					69 kV					
	Lagging power factor										
	0.7	0.8	0.9	0.95	1.00	0.7	0.8	0.9	0.95	1.00	
Underground subtransmission [†]											
Aluminum:											
No. 1/0	18.3	19.9	21.1	21.5	21.0						
No. 2/0	15.4	16.5	17.4	17.6	16.9						
No. 4/0	10.7	11.2	11.5	11.4	10.5						
350 kcmil	7.69	7.84	7.77	7.55	6.50	8.04	8.10	7.92	7.62	6.38	
500 kcmil	6.15	6.12	5.88	5.59	4.50	6.53	6.43	6.10	5.74	4.48	
750 kcmil	4.96	4.80	4.44	4.10	3.00	5.25	5.05	4.63	4.23	3.01	
1000 kcmil	4.32	4.12	3.73	3.37	2.30	4.69	4.44	3.96	3.55	2.32	
Overhead subtransmission [‡]											
ACSR:											
No. 4	42.9	45.5	47.3	47.5	44.7	43.6	46.1	47.7	47.8	44.7	120
No. 2	31.5	32.5	32.7	32.1	28.4	32.2	33.1	33.1	32.4	28.4	165
No. 1/0	24.1	24.1	23.2	22.1	18.0	24.8	24.7	23.7	22.4	18.0	225
No. 2/0	21.6	21.2	20.1	18.8	14.6	22.3	21.8	20.5	19.1	14.6	260
No. 4/0	17.3	16.6	15.1	13.8	9.66	18.0	17.2	15.5	14.1	9.66	355
336.4 kcmil	12.7	11.8	10.4	9.13	5.57	13.4	12.4	10.8	9.44	5.57	480
477 kcmil	11.2	10.3	8.72	7.44	3.92	12.0	10.9	9.15	7.75	3.92	605
795 kcmil	9.73	8.68	7.06	5.78	2.37	10.4	9.28	7.49	6.09	2.37	850

Note: 1 in = 25.4 mm; 1 in² = 645 mm²; 1 ft = 0.3048 m. Regulation of copper conductors can be estimated with reasonable accuracy as that of aluminum conductors two sizes larger. For ampacities of cables, see Tables 18-22 and 18-23.

*Values in the table give the difference in absolute value between sending-end and receiving-end line-to-neutral voltages of a balanced 3-phase circuit.

†Underground cable impedances are based on 90°C conductor temperature with close triangular spacing of cables using typical solid-dielectric insulation, 100% insulation level, single conductor, shielded and jacketed.

‡Overhead conductor impedances are based on 50°C conductor temperature, ACSR construction, 600 A/in² density with 60-in equivalent spacing for 35 kV and 90 in for 69 kV.

The permissible voltage drop is $0.05 \times 69,000/\sqrt{3} = 1991.92$ V line-to-neutral. The corresponding permissible voltage drop per 100,000 A · ft is

$$\frac{1991.92}{141.38} = 14.1 \text{ V/100,000 A} \cdot \text{ft}$$

From Table 18-2 it is seen that this corresponds approximately to No. 4/0 ACSR.

Subtransmission System Patterns. A wide variety of subtransmission system designs are in use, varying from simple radial systems to systems similar to networks. The radial system is not generally used because most utilities today plan their subtransmission-distribution substation systems so that one major contingency such as outage of a subtransmission circuit or failure of a distribution substation transformer will not result in loss of load—or at least the loss of load will be of short duration while automatic switching operations take place. Thus, loop and multiple circuit patterns predominate. Figures 18-8 and 18-9 illustrate the basic nature of these two patterns. The loop pattern implies that a single circuit originating at one bulk power source “loops” through several substations before terminating at another bulk source or even at the original source. Reinforcing ties, as indicated by the dotted connection, are used when the number of substations exceeds some predetermined level.

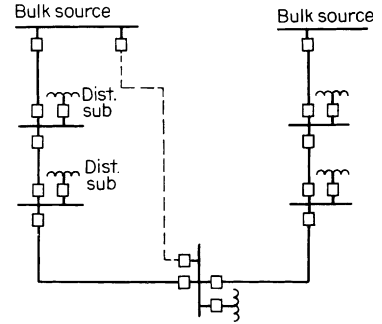


FIGURE 18-8 Loop pattern.

Multiple circuit pattern implies the use of two or more circuits which are tapped at each substation, as illustrated in Fig. 18-9. The circuits may be radial or may terminate in a second bulk power source. Many variations of the two basic patterns are found. From a recent informal survey of approximately 50 major utilities, it appears that the two patterns are about equally used.

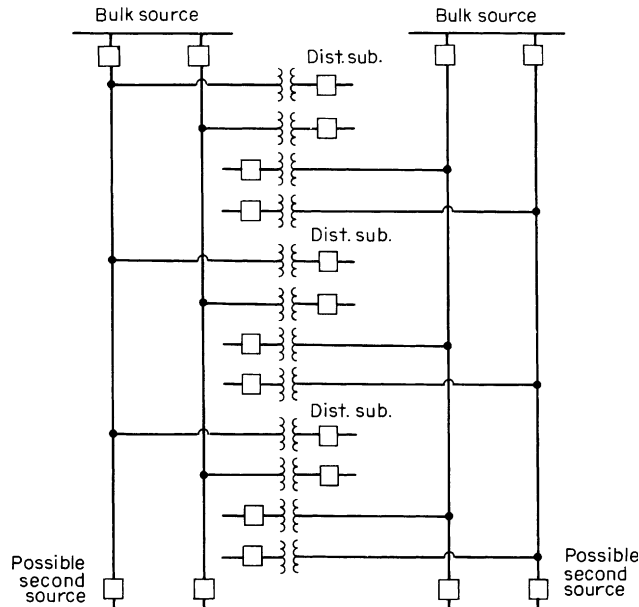


FIGURE 18-9 Multiple pattern.

A vast majority of today's subtransmission is of overhead construction, much of it built on city streets as contrasted with private rights of way. However, appearance and environmental considerations, difficulty in obtaining substation sites and rights of way, and rapid growth of underground distribution are certain to exert continuing pressure on the undergrounding of subtransmission. Even with the use of direct-buried, solid-dielectric cables, the cost of underground subtransmission is many times the cost of overhead circuits, particularly where the overhead subtransmission can be built on city streets.

Thus, a requirement to build future subtransmission underground would have major impact on the balance of overall subtransmission-substation-primary distribution costs. It undoubtedly would focus attention on minimizing the amount of subtransmission circuitry needed to cover the load area, which in turn would favor

Fewer, larger substations

Loop subtransmission pattern rather than multiple parallel circuits

Depending on load density in this area, it *could* favor

Higher primary voltage

Higher subtransmission voltage

Changes in either subtransmission or primary voltage levels are major decisions which require study in depth and ultimately the commitment of large financial resources.

18.6 PRIMARY DISTRIBUTION SYSTEMS

The primary distribution system takes energy from the low-voltage bus of distribution substations and delivers it to the primary windings of distribution transformers.

Overhead Primary Systems. Typically, overhead primary distribution systems have been operated as radial circuits (normally open loops) from the substation outward. Figure 18-2 shows schematically a typical primary feeder in a predominantly residential area; an overhead 12.47Y/7.2-kV system is used for illustrative and functional purposes, but underground systems will be discussed later.

The main feeder backbone usually is a 3-phase 4-wire circuit from which the single-phase lateral or branch circuits are tapped through fuse cutouts to protect the system from faults on the lateral circuits. The single-phase lateral circuits consist of one phase conductor and the neutral. Distribution transformers are connected between the phase and the neutral; in this case they would have a rating of 7200 V.

Utilities use automatic reclosing feeder breakers and line reclosers to minimize service interruptions. However, serious problems involving the main will cause an outage to some or all of the feeder until line crews can locate the problem and manually operate pole-top disconnecting switches appropriately to isolate the problem and to pick up as much load as possible from adjacent feeders. Switches of this kind usually are found in both the main and lateral circuits, as indicated in Fig. 18-2. Also, it is often possible to make and to remove connections while the system is energized through the use of hot-line tools, hot-line clamps, insulated bucket trucks, etc.

Generally, this approach has provided an acceptable level of service because overhead system troubles are relatively easy to locate, and repair times are short. However, when the entire primary system is installed underground, while the frequency of serious trouble is expected to be lower than in overhead systems, it is likely that the time involved in pinpointing the location and making repairs will be much longer than in overhead systems.

Underground System. While a relatively small percentage of new general-purpose feeders is being installed totally underground, the trend is growing and is expected to continue to grow.

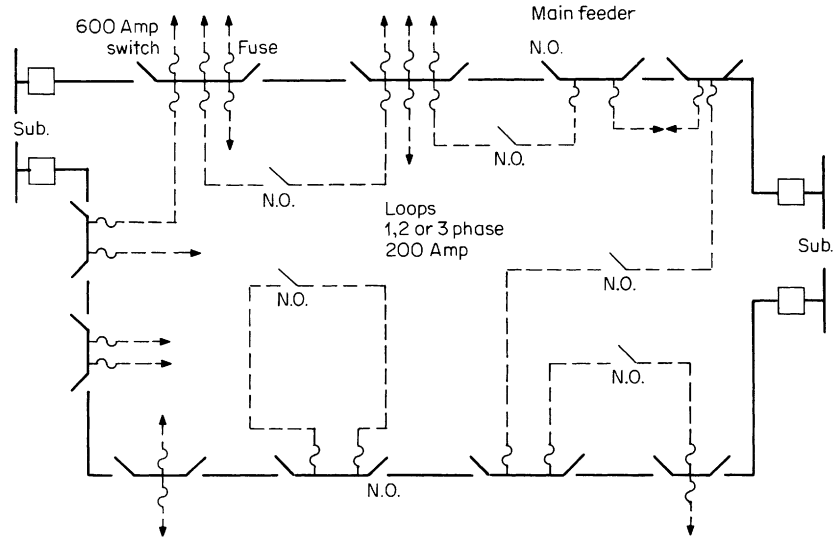


FIGURE 18-10 Typical main-feeder underground circuit. (All switches closed unless shown otherwise.)

Since it is difficult to accomplish many maintenance and operating functions on an underground system while it is “hot,” or energized, in contrast to overhead-system practices, specific provisions must be made in the system design to incorporate needed sectionalizing and overcurrent protective equipment.

The main feeder plan shown in Fig. 18-10 is reasonably typical of present practice on underground systems supplying basically residential and small commercial loads. Note that the main feeders are operated radially, but with normally open ties to adjacent main feeders. The main feeder switches usually are 3-phase, 600-A, manually operated load-break switches. The single-phase and 3-phase lateral circuits also are operated as normally open loops.

Switching in the 200-A circuits can be accomplished by means of either load-break switches or separable, insulated cable connectors. Usually, two main feeder switches are grouped along with the lateral circuit switching and protective equipment into one piece of pad-mounted equipment.

The primary feeders supplying secondary-network systems in metropolitan areas usually are radial 3-wire circuits consisting of 3/c cables in underground duct lines. The 3-phase network transformers are T-tapped to the primary feeders.

Automation. With increasing emphasis on reliability of service, a definite trend is under way to make greater use of protective and sectionalizing equipment in the primary system in order to minimize the number of customers involved in an outage and to reduce the outage time. Proposed schemes run the gamut from manually operated devices to automatic devices remotely controlled from distribution centers. The remote-controlled schemes vary from some type of supervisory control to computer-controlled systems with built-in logic to cope quickly with the various problems which may arise.

Primary-Distribution-System Voltage Levels. Since World War II, the 15-kV distribution class has become firmly entrenched and today represents 60% to 80% of all primary distribution activity. Very little expansion of lower-voltage systems is taking place. There is a trend, however, toward increasing usage of primary voltage levels above the 15-kV class. This trend has an impact on substation and subtransmission practices as well because higher primary voltages almost axiomatically lead to larger substations and higher subtransmission voltages.

The two principal voltages above 15 kV are 24.49Y/14.4 kV and 34.5Y/19.92 kV. New line additions at these voltage levels now average more than 20% of those at 15 kV.

To achieve economy, the higher primary voltages also require heavier feeder loadings which could imply reduced service reliability because more customers are affected by primary faults. Greater use of automatic switching and protective equipment can do much toward preserving a level of reliability to which the public has become accustomed. This is another reason that most observers believe that an increased amount of automation is inevitable in our distribution systems.

For example, a typical 12.47-kV feeder serves a normal peak load on the order of 6000 to 7000 kVA. On this basis, the probable peak loading of a fully developed 34.5-kV feeder would be expected to be in the neighborhood of 18,000 to 20,000 kVA.

Why go to high-voltage distribution (HVD)? Most of today's systems in the 15-kV class are not voltage-drop-limited, and cost of higher-voltage laterals and associated equipment needed to cover the load area is greater. The major economic advantages are:

1. Larger (and fewer) substations
2. Fewer circuits
3. Possibility of eliminating a system voltage-transformation level where the new primary voltage is the former subtransmission level

Other advantages of HVD which are difficult to evaluate in dollars are:

1. Reduced losses in early stages of development
2. Reduced voltage regulation
3. Greater distance or area coverage
4. Fewer circuits per route (reduced congestion)
5. Fewer circuit positions at substations
6. Fewer substation sites
7. Greater flexibility in supplying large spot loads

Some of the disadvantages of HVD have been

1. Cost of equipment
2. Reliability due to increased exposure
3. Higher equipment failure rates
4. Operability

Conductor Sizes. The conductor sizes used in overhead primaries generally range from No. 2 AWG to 795 kcmil. ACSR and aluminum conductors have almost entirely displaced copper for new construction. Aerial cable is used occasionally for primary conductors in special situations where clearances are too close for open-wire construction or where adequate tree trimming is not practical. The type of construction more frequently used consists of covered conductors (nonshielded) supported from the messenger by insulating spacers of plastic or ceramic material. The conductor insulation, usually a solid dielectric such as polyethylene, has a thickness of about 150 mils for a 15-kV class circuit and is capable of supporting momentary contacts with tree branches, birds, and animals without puncturing. This type of construction is commonly referred to as *spacer cable*.

The conductor sizes most commonly used in underground primary distribution vary from No. 4 AWG to 1000 kcmil. Four-wire main feeders may employ 3- or 4-conductor cables, but single-conductor concentric-neutral cables are more popular for this purpose. The latter usually employ crosslinked polyethylene insulation, and often have a concentric neutral of one-half or one-third of the main conductor cross-sectional area.

The smaller-sized cables used in lateral circuits of URD systems are nearly always single-conductor, concentric-neutral, crosslinked polyethylene-insulated, and usually directly buried in the earth. Insulation thickness is on the order of 175 mils for 15-kV-class cables and 345 mils for 35-kV class with 100% insulation level.

Stranded or solid aluminum conductors have virtually supplanted copper for new construction, except where existing duct sizes are restrictive. With the solid-dielectric construction, in order to limit voltage gradient at the surface of the conductor within acceptable limits, a minimum conductor size of No. 2 AWG is common for 15-kV-class cables, and No. 1/0 AWG for 35-kV class.

Voltage Regulation of Primary Distribution. Table 18-3 can be used to determine the voltage drop of an existing circuit when the load data are known or to determine minimum conductor size required to meet a given voltage-drop limit. Data are given for various underground-cable and overhead-conductor configurations for 12.47 and 34.5 kV.

Example. What is the voltage drop for a 34.5-kV overhead circuit 3 mi long using 4/0 aluminum conductor and carrying a balanced 3-phase load of 15,000 kVA at 90% power factor: The current is $15,000/\sqrt{3} \times 34.5 = 251$ A. The circuit feet are $3 \times 5280 = 15,840$ ft. Thus $A \cdot ft/100,000 = 251 \times 15,840/100,000 = 39.758$. From Table 18-3, the appropriate voltage drop per 100,000 A · ft is 14.0 V line-to-neutral. Therefore, the total voltage drop for the example is

$$39.758 \times 14.0 = 556.6 \text{ V line-to-neutral}$$

Since normal line-to-neutral voltage is $34,500/\sqrt{3} = 19,920$ V, the percent voltage drop is

$$556.6 \times 100/19,920 = 2.79\%$$

Example. What is the minimum aluminum conductor size to carry 6000 kVA at 90% power factor of balanced 3-phase load over a 2-mi, 12.47Y/7.2-kV feeder with no more than a 3% voltage drop? Load current is $6000/\sqrt{3} \times 12.47 = 277.8$ A. Circuit feet = $2 \times 5280 = 10,560$ ft. Thus

$$\frac{A \cdot ft}{100,000} = \frac{277.8 \times 10,560}{100,000} = 29.34$$

$$\text{Permissible voltage drop} = 0.03 \times \frac{12,470}{\sqrt{3}} = 216 \text{ V}$$

The corresponding drop per 100,000 A · ft is $216/29.34 = 7.36$ V, line-to-neutral. From Table 18-3, this value falls between 477 and 795 kcmil, so that the latter size would be chosen.

Loading. Loading of primary feeders varies greatly depending on primary voltage, load density, emergency loading requirements, etc. Typical peak loads on 15-kV class feeders are 6 to 7000 kVA. Peak loads on 25- and 35-kV class, fully developed feeders probably will be proportionally greater in the future, assuming that appropriate measures can be taken to maintain acceptable reliability of service.

Voltage Drop. Voltage drop in the primary feeder is an important factor in system design; however, it is only one of the many voltage-drop considerations involved in determining the range of voltages delivered to the customers' service entrances. American National Standard, "Voltage Ratings for Electric Power Systems and Equipment (60-Hz)," ANSI C84.1-1995 (R200), defines in detail the voltage ranges which should be observed. Outside the distribution substation, voltage drops occur in the primary system, the distribution transformer, the secondary system, the service drop, and in the users' wiring systems as well. Remedial measures, such as voltage regulators and shunt capacitor banks, can be used to counteract or reduce the voltage drop due to load flow.

A traditional rough rule of thumb has been to allow a voltage drop of about 3% in the primary of urban and suburban systems at time of peak load. Actually, with typical load densities and primary systems of 15-kV class or higher, it is very probable that economic system designs have a primary voltage drop smaller than 3%.

TABLE 18-3 Line-to-Neutral Voltage Drops per 100,000 A · ft* for 12.47Y/7.2 and 34.5Y/19.92 kV and Balanced 3-Phase Loads

Conductor size	Voltage class									Approx. amp. capacity for air moving at 2 ft/s
	12.47Y/7.2 kV				34.5Y/19.92 kV					
	Lagging power factor									
	Underground primary									
Aluminum:										
Concentric neutral—direct buried, cross-linked polyethylene, conductor 70°C, neutral 60°C, earth resistivity 90 Ω · cm ³ , triplex configuration, full installation										
No. 1/0	17.1	18.5	19.8	20.2	19.8	17.6	19.0	20.1	20.4	19.8
No. 2/0	14.1	15.1	16.0	16.3	15.7	14.6	15.6	16.3	16.5	15.7
No. 4/0	9.82	10.4	10.7	10.7	9.96	10.3	10.8	11.0	10.9	9.95
350 kcmil	7.01	7.19	7.17	7.00	6.11	7.37	7.49	7.39	7.16	6.11
500 kcmil	5.66	5.69	5.55	5.31	4.40	6.04	6.00	5.76	5.47	4.40
750 kcmil	4.63	4.55	4.30	4.03	3.12	4.95	4.82	4.49	4.16	3.11
1000 kcmil	4.10	3.98	3.69	3.41	2.52	4.37	4.20	3.85	3.52	2.51
Single conductor shielded and jacked, cross-lined polyethylene, conductor 70°C, ungrounded shield, triplex configuration, full insulation										
350 kcmil	7.29	7.49	7.51	7.35	6.47	7.55	7.72	7.67	7.47	6.47
500 kcmil	5.78	5.82	5.67	5.45	4.54	6.08	6.07	5.86	5.58	4.54
750 kcmil	4.64	4.54	4.26	3.97	3.02	4.88	4.74	4.41	4.08	3.02
1000 kcmil	4.02	3.85	3.52	3.21	2.26	4.23	4.03	3.65	3.31	2.26
Overhead primary†										
No. 4	42.3	45.4	47.8	48.5	46.6	43.4	46.3	48.5	49.0	46.6
No. 2	29.8	31.2	32.0	31.9	29.3	30.9	32.2	32.7	32.4	29.3
No. 1/0	21.8	22.2	22.1	21.5	18.5	23.0	23.2	22.8	22.0	18.5
No. 2/0	19.0	19.1	18.6	17.8	14.7	20.1	20.0	19.3	18.3	14.7
No. 4/0	14.7	14.3	13.3	12.4	9.20	15.9	15.3	14.0	12.7	9.20
336.4 kcmil	11.8	11.2	9.97	8.91	5.80	13.0	12.1	10.7	9.41	5.80
477 kcmil	10.4	9.58	8.27	7.18	4.10	11.5	10.5	8.97	7.68	4.10
795 kcmil	8.22	7.92	6.52	5.40	2.40	9.96	8.88	7.22	5.90	2.40

Note: 1 in = 25.4 mm; 1 ft = 0.3048 m. For ampacities of cables, see Tables 18-23 and 18-24. Regulation of copper for overhead conductors can be estimated with reasonable accuracy the same as that of aluminum conductors two sizes larger. For single-phase overhead primaries, the voltage drop is approximately two times the 3-phase values given in the table. For underground single-phase primaries in concentric-neutral, direct-buried cables, see section on URD systems. Cables are 15- and 35-kV classes, respectively.

*Values in the table give the difference in absolute value between sending-end and receiving-end line-to-neutral voltages of a balanced 3-phase circuit, in volts.

†Overhead conductor impedances are based on 50°C conductor temperature, aluminum conductor with 30-in equivalent spacing for 12.47Y kV and 60-in for 34.5Y kV.

In rural systems which are typified by long lines and light load densities, primary voltage drops may be somewhat larger. This is offset somewhat by the absence of secondaries in serving individual farms; however, the service drops often are longer than in urban systems. The design objective, of course, is to keep delivered voltage to all customers in an acceptable and satisfactory range.

18.7 THE COMMON-NEUTRAL SYSTEM

The 4-wire, multigrounded, common-neutral distribution system now is used almost exclusively because of the economic and operating advantages it offers. Usually, the windings of the substation transformers serving the primary system are wye-connected, and the neutral point is solidly grounded. Occasionally, a small amount of impedance is connected between the transformer neutral and ground in order to limit line-to-ground short-circuit currents on the primary system to a predetermined value. The neutral circuit must be a continuous metallic path along the primary routes of the feeder and to every user location. Where primary and secondary systems are both present, the same conductor is used as the "common" neutral for both systems. The neutral is grounded at each distribution transformer, at frequent intervals where no transformers are connected, and to metallic water pipes or driven grounds at each user's service entrance. The neutral carries a portion of the unbalanced or residual load currents for both the primary and secondary systems. The remainder of this current flows in the earth and/or the water system. For typical conditions, it is estimated that about one-half the return current flows in the neutral conductor, although the division can vary widely depending on earth resistivity and the relative routing of the electric and water systems. Figure 18-11 is a schematic representation of a common-neutral system.

Grounding of Neutral. Rules related to grounding on the utility system neutral are given in the National Electrical Safety Code (NESC), ANSI C2, and regulations governing the grounding of the neutral on users' premises are stated in the National Electrical Code (NEC), NFPA 70. In brief, the secondary neutral is grounded at every service through a metallic water-piping system and through "made electrode grounds" such as other underground metal systems, building steel, or driven ground electrodes. The increasing use of nonmetallic water piping and insulating couplings on metal water systems is requiring the use of other grounding means. The secondary neutral also is grounded at the distribution transformer, usually by means of driven grounds. Although it is often

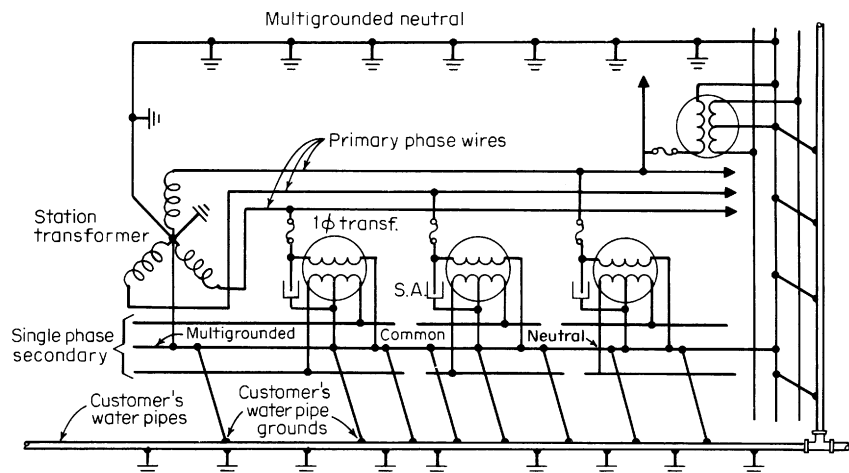


FIGURE 18-11 Common-neutral methods of distribution.

general practice to install a metal butt plate or a wire butt wrap on poles to help in grounding the system neutral and other equipment, the NESC requires two such devices to equal one *made electrode*; as a result, neither can be used to satisfy the NESC requirement for a direct earth ground with a made electrode at each transformer or other arrester location.

The resistance to ground of a typical metallic water-piping system usually is less than $3\ \Omega$. When made electrode grounds are used, they should have a resistance of not more than $25\ \Omega$. Many utilities strive for lower values such as 5, 10, or $15\ \Omega$.

Where there is no secondary neutral as such and no distribution transformers, the primary neutral should be grounded at intervals of not less than 1000 ft. Many utilities require grounding at smaller spacing, such as 500 ft; to meet the NESC requirements for a multigrounded neutral, there must be a minimum of the equivalent of four made electrodes in *each* mile. In URD systems, the primary circuits usually are in direct-buried, concentric neutral cable, so that excellent grounding is obtained.

The neutral must have a continuous metallic path between the substation and users' services. No disconnecting devices should be installed in the common neutral. In no case should the earth or buried metallic-piping systems be used as the only path for the return of normal load current.

Size of Primary Neutral. On single-phase primary circuits (phase and neutral), the neutral conductor should be large enough to carry almost as much current as the phase conductor. Often the same neutral conductor size is used for both, or the neutral has "100%" conductivity.

In 3-phase primary circuits carrying reasonably balanced load, the neutral conductor can be considerably smaller than the phase conductors; 50% conductivity is not uncommon; some utilities specify size of neutral conductor, such as No. 1/0 aluminum, regardless of the size of the phase wires.

Secondary-system neutral conductors are often the same size as the phase conductors where open-wire construction is used. Where triplexed construction is used, the neutral frequently has a reduced cross section.

4-Wire vs. 3-Wire Systems. The 4-wire, common-neutral primary system has many advantages over 3-wire systems:

1. Single-phase branch circuits, or laterals, consist of one insulated phase conductor and the neutral, rather than two insulated phase conductors. The economic advantage is very great in underground systems.
2. On overhead systems, only one lightning arrester is required at each single-phase distribution transformer, rather than two.
3. Only one primary bushing or cable termination is needed on each single-phase distribution transformer, rather than two. In the case of underground systems where the primary "loops through" each distribution transformer, two primary cable terminations or connectors are needed, rather than four.
4. Only one fuse or fuse cutout is needed in the primary of each single-phase distribution transformer. Not only is this a substantial economic advantage, but a short circuit in the primary of the transformer is interrupted positively by the action of a single fuse, and primary voltage is thereby removed from the transformer. In the case of the 3-wire system with the distribution transformer connected phase-to-phase, a second fuse must operate to remove primary voltage and the fault. There may be appreciable time between operation of the two fuses during which fault current continues to flow and abnormal voltages may be experienced by the user.
5. Single-phase primary lateral circuits can be protected by a single fuse cutout, rather than two. Line-to-ground short circuits are promptly cleared by operation of one fuse and voltage removed from the branch circuit. In a 3-wire system (assumed grounded at the substation), single-phase lateral protection, if used, would require two fuse cutouts; a line-to-ground fault would blow only one fuse, leaving all the distribution transformers on that circuit excited at only 58% of normal as long as the faulted phase remains grounded. Under these conditions users' equipment would be exposed to abnormally low voltage. The ability to fuse lateral circuits contributes substantially to

reliability of service, since a major amount of the total circuit exposure comprises the primary laterals in residential areas.

Common-Neutral and Telephone Circuits. Usually, no problems are encountered in the joint use of poles for overhead distribution circuits and telephone circuits, particularly when the telephone circuits are in cable, as is now common practice. Also, in underground residential circuits, power cables and telephone cables often are installed in the same trench with no intentional physical separation of the power and communication facilities, that is, “random lay.” Where separate grounding electrodes are employed for supply and communication facilities at customer’s premises, the electrodes shall be bonded together with not less than No. 6 AWG copper wire.

18.8 VOLTAGE CONTROL

System Voltage Levels and Voltage Ranges. Since about 1900, there have been several recommendations for certain voltages as standard or preferred for primary and secondary distribution systems, as well as for higher-voltage systems. The latest listing of standard system voltages is American National Standards Institute (ANSI) Standard C84.1-1995(R200), “Voltage Ratings for Electric Power Systems and Equipment (60 Hz).” This standard was formulated by both utilities and manufacturers, and its recommendations are followed by both segments of the industry. Observance of this standard enables the utilities and manufacturers to work in harmony. In many states, ANSI C84 is the basis for rulings of the regulatory commission as far as voltage requirements are concerned.

This standard designates certain standard nominal voltages, including 120/240 V single-phase, 480Y/277 V, 12,470Y/7200 V, as well as the higher primary voltages, 24,940Y/14,400 V and 34,500Y/19,920 V, and others.

Using the nominal 120/240-V system as an example, the standard designates two different ranges of voltage, range A and range B. Range A service voltage specifies that a utility supply system be so designed and operated that most service voltages are within the limits specified, for example, 114/228 and 126/252 V. The occurrence of service voltages outside these limits is to be infrequent.

With the typical voltage drops between the service entrance and the points of utilization, the utilization equipment is designed and rated to give fully satisfactory performance within range A.

Range B service voltage includes voltages above and below range A that necessarily result from practical design and operating conditions on supply or user systems. These conditions are limited in extent, frequency, and duration. When they occur, corrective measures should be undertaken within a reasonable time to improve voltages to meet range A requirements.

Insofar as practicable, utilization equipment is designed to give acceptable performance within range B. The design and operating bogey of the utilities is to provide service voltage to all customers at all times within range A limits.

Voltage Profiles. It is usually convenient to discuss distribution-feeder-voltage regulation in terms of voltage *profiles* of the feeder, because the voltages are everywhere different on the feeder. A profile is simply a graph of feeder-voltage magnitude versus location on the feeder. For a simple case of one load at the end of the feeder (assuming uniform conductor), the one-line diagram and profile are as shown in Fig. 18-12.

The profile is a straight line between source and the load, and the voltage regulation at any point between is proportional to the distance from the source. It may be, as shown by the dashed-line profile, that minimum load is not zero, in which case the voltage variation is less than the calculated

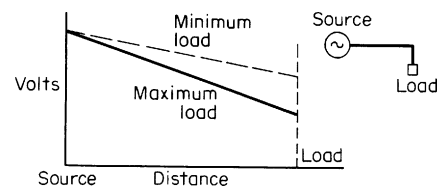


FIGURE 18-12 Voltage profile for concentrated load.

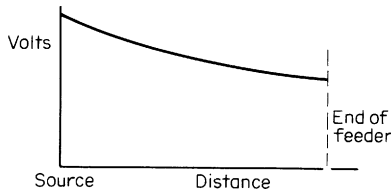


FIGURE 18-13 Voltage profile for distributed load.

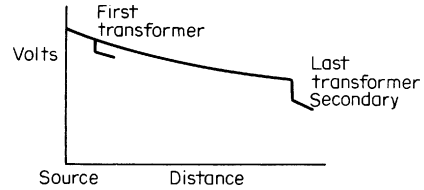


FIGURE 18-14 Additional regulation due to transformer and secondary.

regulation, since regulation is usually calculated on the voltage difference between no-load and full-load conditions. If additional loads are distributed along the feeder, the profile becomes a broken line, and if the load is uniformly distributed, the profile becomes a smooth curve, as shown in Fig. 18-13.

The shape of the profile is of less consequence than knowing the extremes, because there are generally customers connected at all points on the feeder, and no customer's voltage should be too high or too low. Since most feeders neither supply a single load nor are uniformly loaded, it usually is necessary to calculate the voltage profile on a piece-by-piece basis, representing the loads and feeder configurations as accurately as the situation warrants.

In addition to the distribution-feeder-voltage profile, there is additional regulation in the distribution transformer and its secondaries and services. This additional regulation can be added to the profile as shown in Fig. 18-14. For protection of the first customer on the feeder from possible overvoltage, it is usual to assume only a partially loaded transformer rather than one at full load.

It is now possible to establish a limiting band of voltage within which all customers must lie for satisfactory service, usually range A. In turn, this also will establish the maximum permissible difference between the full-load and light-load primary voltage. The problem of holding the right voltage at each customer location at all times may be visualized by referring to Fig. 18-15.

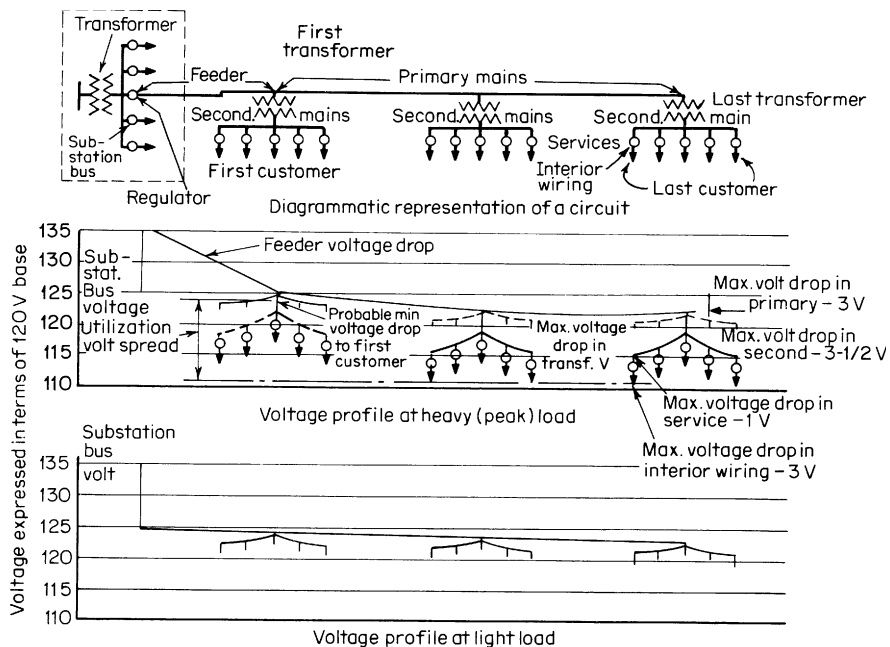


FIGURE 18-15 Distribution circuit with voltage profiles at heavy and light loads.

Voltage Control. As implied in Fig. 18-15, usually there is voltage control equipment in the substation consisting of load-tap changers on the power transformers or bus or feeder voltage regulators. This regulating equipment can control only the voltage *level* of the primary system. It can have no effect on the voltage *spread* between the first and last customers on the feeder.

There are several procedures which can be taken to correct for increasing voltage drops as the load on the feeders grows; among them are capacitors and supplementary feeder-voltage-regulator installations.

The effect of capacitor application is illustrated in Fig. 18-16, where the load is assumed to be uniformly distributed along the feeder, and a capacitor bank is installed as indicated. The capacitor produces a voltage rise because of its leading current flowing through the inductive reactance of the feeder. As is seen in the figure, this voltage rise increases linearly from zero at the substation to its maximum value at the capacitor location. Between the capacitor location and the remote end of the feeder, the rise due to the capacitor is at its maximum value.

When the capacitor voltage-rise profile is combined with the original feeder profile, the resulting net profile is obtained. The capacitor has increased the voltage *level* all along the feeder, resulting also in a reduced voltage *spread*.

In practical applications, the capacitor bank can be a permanently connected or “fixed” bank as shown or an automatically switched bank. The fixed bank is limited in size by the allowable voltage rise during light-load conditions, and therefore may not produce sufficient voltage rise during heavy-load conditions. It can be supplemented by additional switched capacitors which automatically switch on at heavy-load conditions and off again as the load decreases.

The effect of applying a supplementary feeder-voltage regulator is shown in Fig. 18-17. Note that the regulator produces no voltage effect between the source and the regulator location and its entire boost effect is between the regulator location and the remote end of the feeder.

A typical primary feeder serves distributed loads, as well as concentrated loads, and may also have shunt capacitors and supplementary voltage regulation, such that all these previous concepts must be employed in studying voltage conditions.

Voltage Regulation. Voltage regulation in distribution substations usually is accomplished by individual feeder-voltage regulators or by automatic load-tap-changing equipment in the substation transformers. Individual feeder-voltage regulators are advantageous where feeders of differing lengths and diverse load characteristics are supplied from the same substation bus. Automatic load-tap-changing equipment in the power transformer provides voltage control on the substation bus, or group regulation, when feeder lengths and load characteristics are reasonably homogeneous.

Voltage control is needed to compensate not only for the voltage regulation in the subtransmission system and substation transformer, which is measurable at the substation, but also for the voltage regulation which occurs in the distribution transformers and in the primary and secondary systems beyond the substation. The latter portion of the overall system voltage regulation is a function

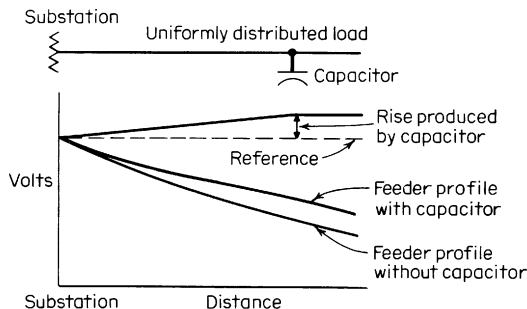


FIGURE 18-16 Effect of shunt-capacitor application.

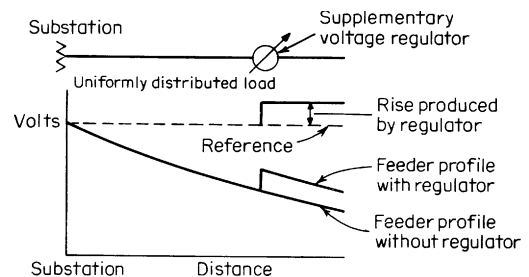


FIGURE 18-17 Effect of supplementary voltage regulator.

of the load flow and system impedances and cannot be measured directly at the substation. Therefore, the control systems of the voltage regulators or tap-changing equipment not only sense the voltage at the substation but also usually contain a “line-drop compensator” which simulates the voltage drop between the station and some point in the distribution system and controls the regulating equipment accordingly. Switched shunt capacitor banks sometimes are installed at the distribution substation as part of the overall system voltage control.

Feeder-Voltage Regulator. In the typical radial primary system, it is often necessary to regulate the voltage of each feeder separately by means of feeder-voltage regulators. These regulators may be of single-phase or 3-phase construction. The former are available in sizes from 25 to more than 400 kVA, the latter from 500 to 2000 kVA. For distribution-system application they are commonly available for voltages from 2.5 kV to 34.5 kV grd Y. Regulators commonly are capable of raising or lowering the voltage delivered to the feeder by 10% and normally are rated on this basis.

Modern voltage regulators all are of the step-voltage type, which has completely supplanted the earlier induction-voltage regulators. The step-voltage regulator basically is an autotransformer which has numerous taps in the series winding. Taps are changed automatically under load by a switching mechanism which responds to a voltage-sensing control in order to maintain voltage as close as practicable to a predetermined level. The voltage-sensing control receives its inputs from potential and current transformers and provides control of system voltage level and bandwidth. In addition, it permits selection of line-drop compensation and provides features such as operation counter, time-delay selection, test terminals, and control switch.

Most feeder-voltage regulators are of the 32-step design. Since they usually operate over a range of voltage of 20%, the voltage change per step is $\frac{5}{8}\%$. If the full range of regulation of $\pm 10\%$ is not required, the regulators can carry more than rated current. For example, operating with a range of $\pm 5\%$, 160% of rated current can be carried.

Line-Drop Compensator. In simplified terms, the regulator voltage (local voltage) is stepped down by means of a potential transformer and fed to the control system, where it is compared with the desired and preset voltage level. If the actual voltage deviates from the preset level by more than $\pm \frac{1}{2}$ of the bandwidth, which also is preset by the operator, the tap-changing mechanism operates, after a preset time delay, to return the voltage within the preset band. From a practical point of view, the minimum bandwidth is twice the size of the voltage step, or $2 \times \frac{5}{8}\% = 1.25\%$. Maintaining a small bandwidth is important in reducing voltage variations and in making full use of the allowable system voltage drop.

The line-drop compensator consists of adjustable resistance and reactance components and is preset to simulate system impedance. By means of a current transformer, current proportional to load current is circulated through the resistance and reactance, producing a voltage signal which is combined with the signal from the local voltage. The net result is that the line-drop compensator causes a higher voltage to be held at the voltage regulator during periods of heavy load. In this way, a constant voltage is held at some point in the system, as determined by the compensator setting. This helps to achieve the goal of minimizing the voltage change with varying loads at any location.

Supplementary Voltage Regulation. In some long primary circuits, such as rural feeders, it is often necessary to provide voltage regulation in addition to that incorporated in substation equipment because of large voltage drops in the system. This supplementary voltage regulation usually is improved by single-phase automatic step regulators in the smaller ratings. These regulators are suitable for pole mounting.

Bus Regulation. Bus regulation at the distribution substation usually is provided by automatic load-tap-changing equipment built into the substation transformer or by large step-voltage regulators.

Switched Shunt Capacitors. Switched shunt capacitors are often applied at distribution substations or out on the primary feeders to accomplish a portion of the overall voltage-regulation job. Most utilities apply shunt capacitors primarily as a tool in economic system design. Usually fixed (unswitched)

shunt capacitors are applied to bring the light-load power factor to more or less 100%. Then, additional automatically switched shunt capacitor banks are added to achieve an economic full-load power factor, which is usually in the order of 95% to 100%.

These capacitors, in addition to their economic functions, such as reducing losses and releasing system capacity, improve system conditions substantially. Usually additional voltage control is needed, however, and this is most economically accomplished with voltage-regulating equipment.

18.9 OVERCURRENT PROTECTION

General Principles. Coordination of overcurrent protection devices means their proper arrangement in series along a distribution circuit so that they function to clear faults from the lines and equipment in accordance with a prearranged sequence of operation. Fuse cutouts, automatic circuit reclosers, sectionalizers, and relayed circuit breakers are the overcurrent protective devices most commonly used. Ratings and characteristics can be obtained from appropriate product bulletins of the manufacturers.

When the protective devices are properly applied and coordinated:

They can eliminate service outages resulting from temporary faults.

They reduce the extent of outages, that is, the number of users affected.

They are helpful in locating the fault, thereby reducing the duration of interruptions.

Main-Line Sectionalizing. Usually, the first protective device on a primary feeder is a circuit breaker or a power-class recloser located in the substation. If the circuit is overhead, the circuit breaker often is provided with reclosing relays so that it operates in much the same manner as a recloser. If the circuit is primarily underground, reclosing is not generally used.

If portions of the main feeder and long branches extend beyond the zone of protection of the relayed breaker or recloser at the substation, additional overcurrent protective equipment usually will be installed out on the main feeder. Manually operated sectionalizing equipment such as pole-top disconnecting switches or solid blade cutouts also are installed at strategic locations along the main feeder to

Provide a convenient means of isolating faults so that repairs can be made after other parts of the feeder are restored to service

Provide means of connecting the feeder to adjacent feeders so that service can be maintained to most customers while repair or maintenance operations are taking place

On underground feeders, this sectionalizing equipment is often in the form of 3-phase, manually operated, load-break switches.

Branch-Circuit Protection. It is exceedingly important to isolate faults on branch and subbranch lines, even short ones, in order to maintain service on the rest of the feeder. Not only does the branch-circuit protection protect the rest of the feeder, but it helps to pinpoint the location of the fault.

Also, there is usually much more mileage and much more exposure in the branch circuit or laterals than in the feeder main. The simple expulsion-fuse cutout is almost universally used for branch and subbranch overcurrent protection. It may be used in combination with reclosers.

On underground feeders, the lateral circuits usually are fused at the point where the main feeder is tapped to establish the lateral. Often, the fuses for several lateral circuits are grouped into a sectionalizing equipment which may also incorporate main-feeder and load-break sectionalizing switches.

Temporary Fault Protection. On overhead distribution circuits, a large portion of the faults are of a temporary nature or are potentially of a temporary nature. For example, some types of transitory

faults include momentary contacts with tree limbs and lightning flashover of insulators or crossarms where no sustained 60-Hz short-circuit current is established and no protective devices operate. Other types of faults which result in 60-Hz follow current can be of a transient nature if the circuit voltage can be removed quickly for a short period of time and then restored after the fault path has recovered adequate dielectric strength. Such faults can result from lightning flashovers, bird or animal contacts, conductors swinging together, etc. Reclosers and reclosing breakers provide the function of fault deenergization, pause for deionization of the arc path, and reestablishment of voltage.

If the fault has disappeared during the “dead time,” the reclosure is successful. If not, one or more additional reclosing cycles may be attempted. If the fault persists after the prescribed number of reclosing operations, the breaker or recloser will lock open, or the fault will be removed by operation of a fuse or sectionalizer.

It should be recognized that the reclosing function is provided to eliminate the effects of *temporary* faults only. If all faults were of a permanent nature, reclosing would be pointless. Also, temporary faults on branch circuits result in a momentary outage to all customers on the feeder when reclosing is used. Some utilities, in an effort to reduce the number of momentaries, are allowing the branch fuse to blow for temporary faults. (This is done by eliminating the instantaneous trip.) While this procedure reduces the number of momentaries seen by customers, it has the negative effect of creating a substantial interruption out of a temporary fault condition for the customers on the affected branch.

To provide effective protection against temporary faults, all parts of the feeder should be within the zone of a reclosing device. That is, if the station recloser or relayed circuit-breaker sensing does not reach to the remote ends of the circuit, it should be supplemented with reclosers out on the line. (The term *reach* here is used with the meaning of “sense” faults or “sense and operate” for faults.)

Permanent Fault Protection. Permanent faults are those which require repairs, maintenance, or replacement of equipment by the utility operating department before voltage can be restored at the point of fault. System overcurrent protection is provided to disconnect the faulted portion of the system automatically so that an outage is experienced by a minimum number of consumers. Isolation of permanent faults is usually accomplished by the operation of fuse cutouts. It is also achieved in some cases by operation (to lock out) of reclosers, circuit breakers, or sectionalizers.

Combination of Permanent and Temporary Fault Protection. If all faults were of a permanent nature, low-cost fuse cutouts would be the best solution for primary line protection. If all faults were temporary, automatic reclosing devices capable of covering the entire circuit would be the best solution. In actual practice, both kinds of faults occur, and the problem becomes one of selecting the type of device or combination of devices to provide best overall results. For selection of a system of overcurrent protection, it is necessary to give proper consideration to many factors such as importance of service, total number of faults per year, ratio of temporary to permanent faults, cost to utility of service interruptions, and annual charge on investment.

Selection of Overcurrent Protective Equipment—General. The one-line diagram of a distribution circuit, as shown in Fig. 18-18, will show how a well-coordinated installation of overcurrent protective equipment can be made.

At the left is the substation, which steps down the voltage from high-voltage subtransmission level to primary-distribution voltage level. It is at this point that the distribution system starts. A distribution substation usually has a number of radial 3-phase feeders radiating from it. However, for the purposes of illustration, only a single feeder will be considered, and it is shown extending to the right from the substation. At various points along the feeder, branch lines or laterals are tapped off and in some cases subbranches are tapped from these branches. There are, of course, loads (residences, stores, garages, etc.) all along the feeder, branches, and subbranches. Only a few of these loads are shown, for the sake of clarity of the diagram.

It is general practice to install a fuse on the primary (incoming) line side of each distribution transformer, as shown in Fig. 18-18. This may be a transformer internal fuse or an external fuse installed in a cutout. Transformer fusing will be discussed later. Figure 18-18 shows the basic system to which additional overcurrent protective equipment must be added to assure good service continuity.

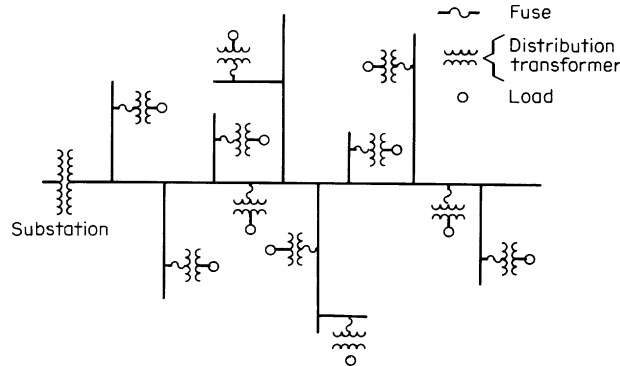


FIGURE 18-18 Distribution feeder.

To properly apply overcurrent protective equipment to this system, it will be necessary to know the highest and lowest (maximum 3-phase and minimum line-to-ground or line-to-line) values of short-circuit currents which can flow if a fault should occur where the feeder leaves the substation, at each branch junction point, and at each subbranch junction point, as well as the minimum line-to-ground short-circuit current which could flow if a fault should occur at the end of any of the branches or subbranches. These short-circuit currents may be calculated easily by conventional methods.

Clearing Nonpersistent or Temporary Faults. Operating records, as well as numerous studies, indicate that a reduction of 75% to 90% in the number of total outages on an overhead system can be attained by the installation of automatic reclosing devices (automatic circuit recloser or reclosing circuit breaker). The recloser or breaker will open the circuit “instantaneously” when a fault occurs, and reclose it after a short period of time.

Referring to Fig. 18-18, automatic circuit reclosers will be applied to protect the entire system against temporary faults. To achieve this sort of protection, the first recloser should be installed on the main feeder at the substation or the power circuit breaker at the substation should be equipped with overcurrent and reclosing relays.

In applying reclosers to do this job, certain factors must be considered: (1) The voltage rating of the recloser must be high enough to meet the requirements of the system. (2) Load current, or the amount of current which flows at the point of installation of the recloser under full-load conditions, should not exceed the amount of current which the manufacturer has rated the recloser to carry continuously (continuous-current rating). Recloser ratings are usually selected to be 140% of the peak load current of the circuit. This allows for normal load growth. (3) The highest value of short-circuit current which will flow through the recloser and which the recloser must interrupt. This value should not be greater than the highest value of current which the recloser is rated to interrupt (interrupting rating). Typically, a recloser will have a continuous rating of 560 A or less and an interrupting rating of 16,000 A or less. A breaker, on the other hand, will usually handle at least 1200 A continuously and up to about 40 kA under short-circuit conditions.

Referring to Fig. 18-19, a recloser or breaker with reclosing relays will be located at *A* to meet the three application principles mentioned above. This device will be depended on to clear non-persistent faults which occur in the feeder, branches, or subbranches, anywhere within its protective orbit zone *A* (shown by dotted line in Fig. 18-19). This protective zone extends to the point where the minimum available short-circuit current, as determined by calculation, is equal to the smallest value of current which will cause the device to operate. This value of current required to operate the recloser or breaker is called minimum pickup current. For a recloser it is usually equal to *twice the continuous current rating of the recloser*. A fault beyond this zone may not cause the recloser or breaker *A* to operate, and therefore, another recloser, *B*, with a lower minimum pickup current rating, should be installed just inside of zone *A*, thus resulting in so-called overlapping protection.

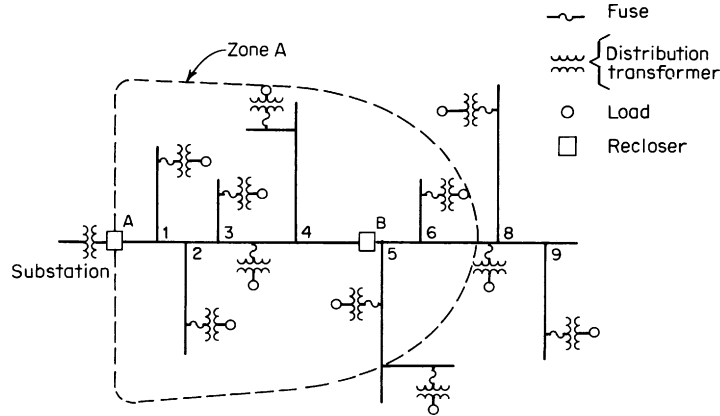


FIGURE 18-19 Distribution feeder with automatic reclosers.

This second recloser, *B* in Fig. 18-19, is placed on the source side (side nearest source of power) of branch 5 so that it can protect the end of this branch from nonpersistent faults which may not cause recloser *A* to operate. It is applied according to the same considerations as was the recloser at *A*. It will be assumed that a fault on the feeder or any branch or subbranch beyond (to the right of) *B* will cause enough current to flow to operate the recloser at *B*. Every point on the entire circuit is now protected against nonpersistent faults because every point is within the protective zone of some reclosing device. Obviously, if every point were not within the protective orbit of some reclosing device, another recloser would have to be installed still farther out on the line.

Clearing Persistent Faults. The first requirement of protecting the circuit against nonpersistent or transient faults has been taken care of by recloser application. It is necessary now to concentrate on the second and third requirements, that is, confining persistent faults to the shortest practical section of line and making persistent faults easy to locate.

If a permanent fault occurs anywhere on the system beyond a recloser, the recloser will operate once, twice, or three times instantaneously, depending on adjustment, in an attempt to clear the fault. However, since a persistent fault will still be on the line at the end of these operations, it must be cleared by some means other than the instantaneous recloser operations. For this reason, the recloser is provided with one, two, or three time-delay operations, depending on adjustment. These additional operations are purposely slower (time-delay operations) to provide coordination with fuses or to allow the fault to “self-clear.” If the fault is still on the line after the last opening, the recloser will not close in but lock open.

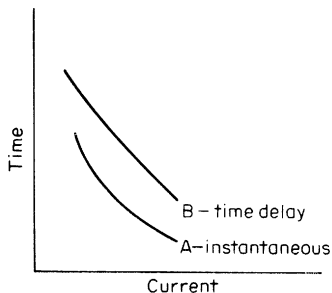


FIGURE 18-20 Recloser tripping characteristics.

Referring to Fig. 18-20, curve *A* represents the instantaneous tripping characteristic with respect to time for the first and second opening of a conventional automatic circuit recloser. Curve *B* represents the tripping characteristics for the third and fourth openings. Following the fourth trip on time delay, the recloser will lock out and must be manually reclosed after the cause of the fault has been remedied.

A persistent fault on a branch or subbranch line *should not* cause a recloser to lock open, since a fault on a relatively unimportant subbranch could shut down the entire circuit, in addition to being extremely difficult to locate. Therefore, some means should be employed to confine outages due to persistent faults to the branch or subbranch on which they occur. This may be done in either of two ways.

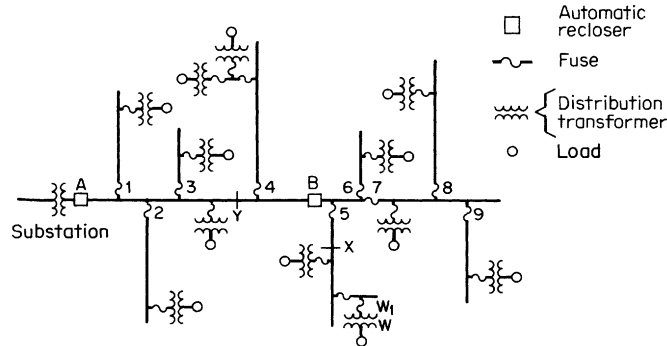


FIGURE 18-21 Distribution feeder with automatic reclosers and fuse cutouts.

One method by which persistent faults can effectively be dealt with is illustrated in Fig. 18-21. A fuse cutout is installed at each branch or subbranch junction to confine outages due to persistent faults to the branch or subbranch on which they occur, that is, fuses 1, 2, 3, 4, etc.

The fuse cutout to be installed at a particular location must be of sufficiently high voltage rating to meet the voltage requirements of the circuit. Its continuous current rating must be equal to or greater than the full-load current at the point of installation. Its interrupting rating must be high enough so that it will successfully open the circuit for any persistent fault occurring beyond it. This may be checked by comparing the interrupting rating of the cutout with the maximum available short-circuit current calculated for the point on the system where the cutout is to be installed.

For an ideal system, when the correct ratings of fuse links are used throughout the system, *no fuse will be blown or even damaged by a temporary fault beyond it; that is, the recloser will open the circuit one, two, or three times on instantaneous operations without the fuse link being damaged.* In many systems, however, where short-circuit levels are very high, it is sometimes impossible to prevent even the largest fuse from operating during a temporary fault. On a permanent fault, the first fuse link on the source side of the fault will be blown, and the circuit thus will be opened by the blowing of the fuse during the third or fourth (time-delay) operation of the recloser, before the recloser will lock open. Hence, the fault will be isolated by the fuse, and the recloser will reset automatically, restoring service everywhere except beyond the blown fuse. The recloser should never lock open on a permanent fault beyond the fuse if it has been properly coordinated with the recloser. Extensive coordination tables are available, as illustrated in Table 18-4, to simplify and facilitate the job of coordinating reclosers with fuse links.

Recloser-Fuse Coordination. Figure 18-22 shows the time-current characteristic curves of the automatic circuit recloser similar to those shown in Fig. 18-20. On these curves, the time-current (TC) characteristics of a fuse *C* are superimposed. It will be noted that fuse curve *C* is made up of two parts; that is, the upper portion of the curve (low current range) represents the total clearing-time TC curve, and the lower portion (high current range) represents the melting TC curve for the fuse. The intersection points of the fuse curves *C* with the recloser curves *A* and *B* illustrate the limits between which coordination will be expected. Basically, this is correct within the interest of simplicity. However, to establish intersection points *a* and *b* accurately and to prepare coordination charts, it is necessary that the characteristic curves of both recloser and fuse be shifted, or modified, to take into account alternate heating and cooling of the fusible element as the recloser goes through its sequence of operations. For example, if the fuse is to be protected for two instantaneous openings, it is necessary to compute the heat input to the fuse during these two instantaneous recloser operations.

Curve *A'* in Fig. 18-23 is the equivalent TC characteristic of two instantaneous openings (*A*) and is compared with the fuse-damage curve, which is 75% of the melting-time curve of the fuse. This will establish the high current limit of satisfactory coordination indicated by intersection point *b'*. To establish the low current limit of successful coordination, compare the total heat input to the fuse

TABLE 18-4 Automatic Recloser and Fuse Range of Coordination*

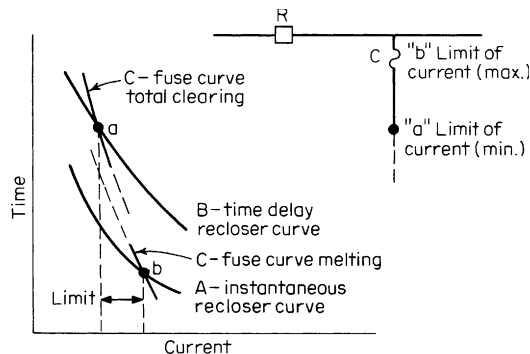
Recloser rating, rms A (continuous)		Fuse link ratings, rms A							
		25T	30T	40T	50T	65T	80T	100T	140T
		Range of coordination, rms A							
50	Min	190	480	830	1200	1730	2380		
	Max	620	860	1145	1510	2000	2525		
70	Min	140	180	365	910	1400	2000	2750	
	Max	550	775	1055	1400	1850	2400	3200	
100	Min	200	200	200	415	940	1550	2280	
	Max	445	675	950	1300	1700	2225	3050	
140	Min		280	280	280	720	710	1750	
	Max		485	810	1150	1565	2075	2875	
200	Min				400	400	400	880	3200
	Max				960	1380	1850	2600	4000
280	Min						620	620	1350
	Max						1500	2200	4000

*Recloser sequence: two instantaneous plus two standard time-delay operations.

represented by curve B' , which is equal to the sum of two instantaneous (A) plus two time-delay (B) operations, with the total clearing-time curve of the fuse. The point of intersection is indicated by a' .

On the basis of all corrections added, the fuse will coordinate successfully with recloser between the current limits of a' and b' .

To further clarify what is meant by coordination within prescribed limits, refer to Fig. 18-21—branch 5 and recloser B —and also Fig. 18-23 to establish how coordination is achieved between the limits of a' and b' . Assume that fuse 5 beyond recloser B is to be protected against blowing or being damaged during two instantaneous operations of the recloser *in the event of a transient fault at X*. If the maximum calculated short-circuit current at the fuse location does not exceed the magnitude of current indicated by b' , the fuse will be protected against blowing during all transient faults. By observation of the characteristics in Fig. 18-23, for any magnitude of short-circuit current less than b' but greater than a' , the recloser will trip on its instantaneous characteristic once or twice to clear the fault before the fuse-melting characteristic is approached. On the other hand, *if the fault at X is persistent*, the fuse at 5 should blow before the recloser B locks out. If the minimum (line-to-ground) calculated short-circuit current available *at the end of branch 5* is substantially greater than the

**FIGURE 18-22** Recloser and fuse time-current characteristics.

current indicated by a' , the fuse will blow (Fig. 18-23) in accordance with the total clearing characteristic, probably before the first time-delay characteristic of the recloser is approached.

The correct fuse link for any application may be selected by comparing its TC characteristics curve with those of the recloser and making certain allowances and corrections as shown. However, tables have been prepared similar to Table 18-4 to simplify greatly the job of coordinating reclosers with fuse links. This table shows the maximum and minimum currents at which certain ratings of fuse links will coordinate with certain ratings of reclosers. The only requirement in their use is a knowledge of the available short-circuit currents and load currents on the system.

Other sequences of recloser operation can be employed, but one instantaneous and two time-delay operations is the combination most widely used. In some cases, it is necessary to coordinate recloser operation with a relayed breaker at the substation. The principles of coordination are similar to the previous discussions, but a detailed study is beyond the scope of this handbook. This is also true of the application requirements for power-class reclosers for substation and line protection.

Fuse-to-Fuse Coordination. It may be desirable to use more than two fuses in series beyond a recloser in order to reduce the number of consumers affected by an outage. An example of this would be the fuses at points 7, 8 and at transformers on branch 8 in Fig. 18-21. The coordination of these fuses in series beyond the recloser B may be accomplished by coordinating adjacent fuses first with each other and then with the recloser in the manner just outlined.

Figure 18-24 illustrates the general principle of coordinating fuses in series. Fuse 7 is called the *protected fuse*, and fuse 8 is called the *protecting fuse*. For perfect coordination, fuse 8 must clear the circuit during a fault anywhere beyond it, such as at X , before fuse 7 is damaged or partially melted. From this can be seen the requirement for melting-time-current curves plotted to minimum values and total-clearing-time-current curves plotted to maximum values for each fuse-link rating. *Total-clearing-time* curves represent the total time, including melting time and arcing time, plus manufacturing tolerance, that it takes the fusible elements to clear the circuit. *Melting-time* curves represent the minimum time, based on factory test, at which the fusible element melts for various currents. From the melting-time curves, *damaging-time* curves can be determined by applying a factor of safety. It usually is suggested that the damaging-time curve be made by taking 75% of the melting time (in seconds) of a particular size at various current values.

To establish coordination of two fuses in series, it is necessary to compare the total-clearing-time-current curve of the protecting fuse with the damage-time-current curve of the protected fuse. If there is no intersection of these two curves throughout their entire current range, coordination or selectivity can be expected. Where there is an intersection of the curves, the current value indicated by the point of intersection will establish the limit of selectivity.

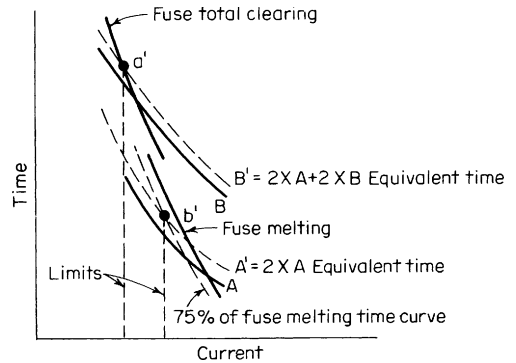


FIGURE 18-23 Recloser and fuse time-current characteristics.

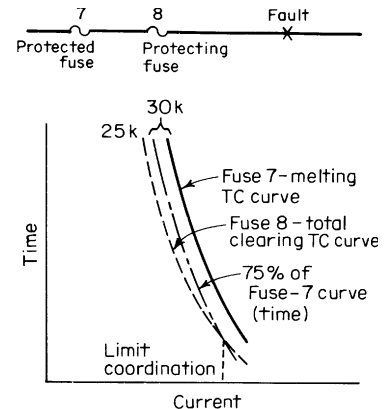


FIGURE 18-24 Fuse time-current characteristics.

TABLE 18-5 Fuse Ratings

Type K EEI-NEMA ratings, A, of the protecting fuse links (8 in diagram)	Type K EEI-NEMA ratings, A, of the protected fuse links (7 in diagram)								
	6K	8K	10K	12K	15K	20K	25K	30K	40K
	Max short-circuit rms A to which fuse links will be protected								
1K	135	215	300	395	530	660	820	1100	1370
2K	110	195	300	395	530	660	820	1100	1370
3K	80	165	290	395	530	660	820	1100	1370
5-A series Hi-surge	14	133	270	395	530	660	820	1100	1370
6K		37	145	270	460	620	820	1100	1370
8K			133	170	390	560	820	1100	1370
10-A series Hi-surge		16	24	260	530	660	820	1100	1370
10K				38	285	470	720	1100	1370
12K					140	360	660	1100	1370
15K						95	410	960	1370
20K							70	700	1200
25K								140	580

Source: General Electric Company.

Because of the inherent characteristics of fuses, the maximum available short-circuit current in that section (determined by calculation) controlled by the protecting link (8 in Fig. 18-24) is the determining current which establishes coordination possibilities.

Most fuse-link manufacturers publish tables which make coordination very simple. These tables eliminate the necessity of comparing actual fuse-characteristic curves. Table 18-5 is illustrative of tables used for fuse-to-fuse coordination. The values in the left-hand column are the protecting fuse ratings and the values across the top are the protected fuse ratings. The numerical values in the table show the magnitude of current or curve intersection points at which, or below which, fuse 7 will be protected by fuse 8. These current magnitudes are maximum values; in other words, for any short-circuit current greater than that shown, fuse 7 will be damaged. Hence, a larger-rated fuse will have to be selected for location 7 or else its position must be changed.

Isolation by Sectionalizer. Another method of isolating persistent faults is to install a device, known as a *sectionalizer*, at locations where a fuse might otherwise be used. A sectionalizer is a device which counts the operations of a backup automatic-interrupting device such as a recloser. It has no interrupting capacity of its own but operates in a predetermined coordination scheme to open a faulted lateral before the backup device locks out.

The sectionalizer opens the circuit after a predetermined number (usually two or three) of operations of a reclosing device. Its opening operation occurs during a period when the reclosing device is open. It can be used to replace a lateral sectionalizing fuse or to replace a lateral recloser where interrupting requirements have grown beyond the capability of the recloser. Among its operating advantages are

It allows coordination with breakers or reclosers where fault current is above 5000 A. Such coordination usually is impossible with expulsion fuses.

It can provide a new sectionalizing point on an existing circuit without upsetting existing over-current coordination, since the device operates as a counter and does not introduce another level of time-current coordination.

Equipment Protection

General. It is necessary to provide overcurrent protection for distribution equipment such as capacitors and distribution transformers:

To protect the system from the effects of equipment failures

To reduce the probability of violent failures

To indicate the location of the fault

A detailed discussion of all aspects of overcurrent protection of equipment is beyond the scope of this handbook. However, because of its importance, a few comments will be included regarding the overcurrent protection of distribution transformers.

Self-Protected Transformers. The term *self-protected distribution transformer* is applied to units which incorporate an internal primary expulsion fuse, a direct-mounted arrester, and an internal secondary circuit breaker. The low-voltage circuit breaker protects the transformer from excessive overload and from some of the faults originating on the secondary system. The expulsion fuse has the sole function of removing a failed transformer from the system.

The rating of the internal expulsion fuse usually is quite large compared with the continuous current rating of the transformer, perhaps 10 to 14 times. This is done

1. To ensure that the fuse is not damaged by the maximum tripping current of the circuit breaker
2. To minimize the possibility of extraneous fuse blowing because of lightning current effects

Another reason is that fuse removal and replacement may require that the transformer be taken to a shop facility.

Transformer internal expulsion fuses are installed at the factory and are given a designating number rather than an ampere rating for coordination purposes. For a 7200-V transformer, the internal expulsion fuse, often called *weak link*, has an interrupting capacity of about 3000 A. Weak links for higher-voltage transformers have somewhat lower interrupting capacity.

Despite the fact that self-protected transformers often are installed at locations on the system where the interrupting capacity of the weak link may be exceeded for a solid fault, experience over the years has been excellent, probably because most transformer failures begin as relatively low fault-current turn-to-turn failures. As the fault current progressively becomes larger, the fuse will operate well before its interrupting capacity is exceeded. Thus, while high-current transformer faults can occur, their frequency of occurrence is very small.

However, there is growing concern among utility companies regarding the occasional violent failures of transformers, and many users are using, or are considering the use of, current-limiting fuses as one method to minimize the energy input into a failed transformer.

The secondary circuit breaker is depended on to provide protection against excessive transformer loads and secondary system faults that occur within its zone of protection, or *reach*. Its TC characteristic should be such that it will always operate before the primary fuse suffers any damage, as illustrated in Fig. 18-25. On the other hand, the breaker should not operate for faults beyond the customer's service-entrance-protective equipment. Likewise, the internal primary fuse should operate to clear transformer faults before damage occurs to the line sectionalizing fuses back toward the source.

Conventional Transformers. Conventional distribution transformers usually are protected by separately mounted expulsion fuse cutouts in series with the primary winding. No secondary overcurrent protection is provided, so protection against extreme overloads or secondary faults, if any, must come from the primary fuse. Therefore, the size of the primary fuse is relatively much smaller than for the self-protected transformer, usually being chosen in the range of 2 to 3 times the full-load current of the transformer.

It is desirable to keep the fuse rating as low as possible consistent with certain application limitations:

1. When a transformer is energized by closing of its cutout or operation of a recloser or other switch, a large "magnetizing inrush" current can occur. Initially, this current can be as much as 20 or more times normal, rapidly decaying to normal in a short time—perhaps $\frac{1}{2}$ to 1 s or more. The primary fuse link must be large enough to avoid damage by the magnetizing inrush current, so it usually is selected at least large enough to carry 12 times rated transformer current for 0.1 s without damage.
2. The primary fuse should not be damaged by lightning currents or arrester discharge currents (depending on connection used) or large magnetizing currents which can result from saturation of the core due to lightning currents. Many utilities assign an arbitrary minimum fuse size which they will employ. With expulsion fuses, 10- or 15-A rating is often designated as the minimum size.

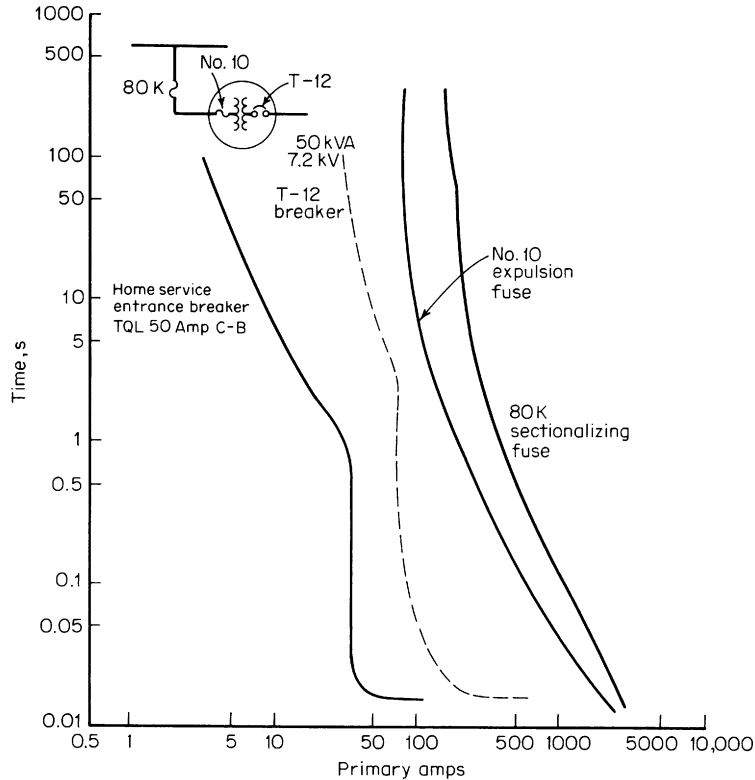


FIGURE 18-25 Overcurrent coordination for self-protected distribution transformer.

With a fuse *rating* of 2 to 3 times rated transformer current, the minimum melting current under long-time conditions will be in the range of 4 to 6 times transformer rating. Consequently, little overload protection is obtained.

In the absence of overload protection, many utilities count on a transformer load-management program or seasonal load-survey techniques to keep their “burnouts” at an acceptable level. Also, the primary fuse has a limited reach as far as secondary faults are concerned; therefore, secondary faults can occur which cannot be “seen” by the fuse. Often these faults—especially on underground systems—will burn clear.

Expulsion Cutouts. Distribution expulsion cutouts are by far the most common type of protective device used on overhead primary-distribution systems. The open-type cutout has generally supplanted the porcelain-enclosed style. The cutout consists of an insulating structure and a hinged fuse tube of hollow cylindrical construction which contains the fuse link. When the fuse link melts, the ensuing arc impinges on the wall of the fibrous tube holder (and usually a small auxiliary tube), generating gas which provides the expulsion action needed to extinguish the fault current. Separation of the fuse link also releases the cutout-latching mechanism so that the fuse holder falls to the open position and can readily be located by operating personnel. The fuse holder also can be switched manually with a switch stick, much like a disconnect switch. In some cases, a solid blade is used in place of the fuse holder to provide a disconnecting function. The cutout also can be provided with load-breaking accessories so that it can be used as a load-break switch.

Generally cutouts are available in 100- and 200-A continuous-current ratings for fuses and 300- or even 400-A with solid blades. Cutouts are available with voltage ratings for all the common primary system voltages and interrupting capacities generally from 1200 up through 16,000 A symmetrical and more.

Fuse links for cutouts are available with a variety of TC characteristics. However, the two most widely used types are the Type K (fast) fuse links and the Type T (slow) links with characteristics as defined in ANSI C37.43. Both types have certain application advantages and disadvantages which must be evaluated by the utility. Ordinarily, a given utility uses one type or the other, not both. Use of the Type K links is believed to be somewhat greater than use of Type T.

Other common types of primary fuses employ fusible elements immersed in oil.

Fuses are not widely used in electric utility secondary systems, with the notable exception of secondary network systems, where *limiters* are frequently used in the secondary cable circuits. Limiters are fusible elements whose TC characteristics are coordinated with the cable size and insulation characteristics to prevent damage to the cable when faults do not burn clear or self-extinguish.

Current-Limiting Fuses. The use of current-limiting fuses in distribution systems has been growing. The fuse generally is constructed of silver wire or ribbon fusible elements—often several in parallel—spirally wound on a core or spider and packed in a quartz-sand filler in a sealed cylindrical glass or epoxy-glass container. Provisions for suitable electrical connections are made at the ends. When operation takes place under high-fault-current conditions, the fusible element melts almost instantaneously at a series of reduced sections all along its length. The resulting arc dissipates its heat rapidly into the surrounding sand, melting the sand around the arc into a glass-like structure called a *fulgorite*. This action builds up the apparent resistance of the fuse extremely rapidly, resulting in a “back voltage” greater than system voltage. Thus, the fault current is limited to a value much less than the available system fault current.

Current-limiting fuses are characterized by

1. High-current interrupting ability. Interrupting ratings of 50,000 A symmetrical or greater are commonly available.
2. Operation is noiseless, and there is no expulsion of the arc or arc products. Thus, the fuse can be “packaged” into relatively confined space in transformers and protective equipment, making it extremely attractive for use on underground systems.
3. In the current-limiting mode of operation, the interrupting time is very fast, one-half cycle or less.
4. Current-limiting action and fast operation reduce the amount of I^2t (or fault energy) let through into failed equipment, thereby reducing resultant damage. In the case of distribution transformers applied on systems of high available fault current, protection by current-limiting fuses can virtually eliminate violent failures due to high fault current.

General-purpose current-limiting fuses are designed to clear fault currents over a broad range. They are defined by ANSI Standard C37.40-3.2.2.2 as fuses capable of interrupting all currents from the maximum interrupting current down to the current causing melting of the fusible element in 1 h. Current-limiting fuses inherently are excellent fault-current interrupters in the high current range. Typical general-purpose fuses operate in the current-limiting mode at fault currents equal to *approximately* 25 times rated current or larger.

Special design and construction techniques are required to obtain clearing of low-fault-current values. For operating times greater than about 0.01 s, the fuses have TC characteristics which are plotted on loglog coordination paper in the same manner as expulsion fuse characteristics.

Backup current-limiting fuses are defined by ANSI Standard 37.40-3.2.2.1 as fuses capable of interrupting all currents from the rated maximum interrupting current down to the rated minimum interrupting current as given by the manufacturer. The low current clearing must be accomplished by an auxiliary device, most commonly an expulsion fuse. In this case, the TC characteristics are a

composite of the two fuses as shown in Fig. 18-26. The backup current-limiting fuse can be retrofitted into existing pole-type distribution transformer installations which have expulsion fuse protection only.

18.10 OVERVOLTAGE PROTECTION

Lightning. Lightning is the most frequent cause of overvoltages on distribution systems. Basically, lightning is a gigantic spark resulting from the development of millions of volts between clouds or between a cloud and the earth. It is akin to the dielectric breakdown of a huge capacitor.

The voltage of a lightning stroke may start at hundreds of millions of volts between the cloud and earth. Although these values do not reach the earth, millions of volts can be delivered to the building, tree, or distribution line struck. In the case of overhead distribution lines, it is not necessary that a stroke contact the line to produce overvoltages dangerous to equipment. This is so because “induced voltages” caused by the collapse of the electrostatic field with a nearby stroke may reach values as high as 300 kV.

The amount of current in a stroke is a statistical quantity, depending on the energy in the cloud and the voltage difference between the cloud and the earth at the start of the stroke. A few stroke currents in excess of 200,000 A have been measured; however, 50% of all stroke currents are less than 15,000 A.

The time duration of the current flow in the majority of the high-current strokes is only tens or hundreds of microseconds. Typically, the current rises to its maximum in 0.5 to 10 μ s, decreases to half value in 20 to 50 μ s, and falls to zero within 100 to 200 μ s. On a 60-Hz basis, these are extremely short times if one considers that one-half cycle is equivalent to $\frac{1}{20}$ s or $1,000,000/120 = 8333 \mu$ s. Numerous field investigations have established the numerical statistics which apply to lightning.

In summary, lightning can produce voltages dangerous to the distribution system and all its component equipment. It poses a major threat to service continuity and must be coped with by means of distribution surge arresters.

Arrester Selection. Choosing an arrester rating for a distribution system is based on the system’s line-to-ground voltage and the way it is grounded. The limiting condition for an arrester does not usually have anything to do with the magnitude of the surges (switching or lightning) that it might see. This is in contrast to the selection of arresters for transmission. In distribution, rating of the arrester is based on the maximum steady-state line-to-ground voltage the arrester might see. This limiting condition is normally caused when there is a line-to-ground fault on one of the other phases.

According to ANSI Standard C62.22, “Guide for the Application of Metal-Oxide Surge Arresters for Alternating-Current Systems,” proper application of arresters on distribution systems requires knowledge of “(1) the maximum normal operating voltage of the power system, and (2) the magnitude and duration of temporary overvoltages (TOV) during abnormal operating conditions. This information must be compared to the arrester MCOV rating and to the arrester TOV capability.”

The MCOV of the arrester is, however, somewhat easier to define because it is approximately 84% of the arrester duty cycle rating. What this means is that a 10-kV duty cycle rated arrester, typically used for a 13.2-kV system, could be operated continuously with a maximum continuous line-to-ground voltage of 8.4 kV or less.

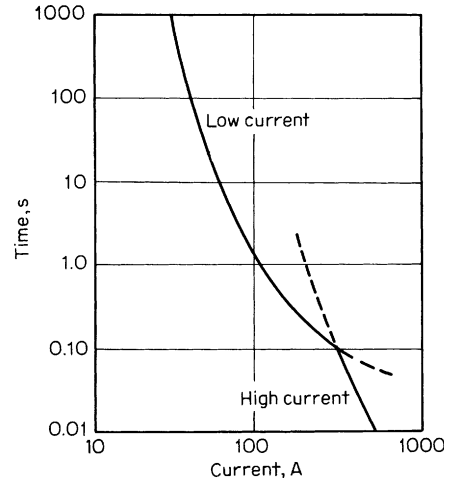


FIGURE 18-26 Time-current characteristic for backup current-limiting fuse in series with expulsion fuse.

TABLE 18-6 Commonly Applied Voltage Ratings of Metal-Oxide Arresters on Distribution Systems^a

System voltage, kV rms		Commonly applied arrester voltage ratings, kV rms duty cycle voltage ratings (MCOV) ^b		
Nominal voltage	Maximum voltage range B ^c	4-Wire multigrounded neutral wye	3-Wire low- impedance ^d grounded ^e	3-Wire high impedance ^d grounded
2400	2540			3 (2.55)
4160Y/2400	4400Y/2540	3 (2.55)	6 (5.1)	6 (5.1)
4260	4400			6 (5.1)
4800	5080			6 (5.1)
6900	7260			9 (7.65)
8320Y/4800	8800Y/5080	6 (5.1)	9 (7.65)	
12000Y/6930	12700Y/7330	9 (7.65)	12 (10.2) ^f	
12470Y/7200	13200Y/7620	9 (7.65) or 10 (8.4)	15 (12.7) ^f	
13200Y/7620	13970Y/8070	10 (8.4)	15 (12.7) ^f	
13800Y/7970	14605Y/8430	12 (10.1)	15 (12.7) ^f	
13800	14520			18 (15.3)
20780Y/12000	22000Y/12700	15 (12.7)	21 (17.0) ^f	
22860Y/13200	24200Y/13870	18 (15.3)	24 (19.5) ^f	
23000	24340			30 (24.4)
24940Y/14400	26400Y/15240	18 (15.3)	27 (22.0) ^f	
27600Y/15930	29255Y/16890	21 (17.0)	30 (24.4) ^f	
34500Y/19920	36510Y/21080	27 (22.0)	36 (29.0) ^f	

^aSpacer cable circuits have not been included—there has been insufficient experience with the application of metal-oxide arresters on spacer cable circuits to include them in this table.

^bFor each duty cycle rating, the maximum continuous operating voltage (MCOV) is also listed.

^cSee ANSI C84.1-1989.

^dLow impedance circuits are typically 3-wire, ungrounded at the source. High impedance circuits are generally ungrounded (i.e., delta). Additional information regarding system grounding is contained in ANSI C62.92, Part 1.

^eLine-to-ground fault duration not to exceed 30 minutes. For longer durations consult manufacturers' temporary overvoltage capability.

^fIndividual case studies may show lower voltage ratings may be used.

Table 18-6, from ANSI C62.22, shows the commonly applied voltage ratings of metal-oxide arresters for distribution systems. All these duty cycle ratings are the same as the rating for the older gapped silicon carbide arresters except at the 13.8-kV level. Typically, a 13.8-kV, 4-wire, multigrounded system has used 10-kV gapped arresters. Today, most of these same utilities are still using 10-kV MOVs. Some utilities, however, have recognized that the 10-kV arrester is very marginal and possibly should be replaced by a 12-kV rating to be on the more conservative side.

TOV. How much voltage shift which will occur is a function of the type of system grounding. For example, on a delta system, a line-to-ground fault will cause a full offset; that is, the line-to-ground voltage will become the line-to-line voltage. Figure 18-27 illustrates this condition. As can be seen, when a phase has a fault there is no current because the transformer is delta-connected. For a 4-wire multigrounded system, there is less voltage rise (Fig. 18-28). The arresters connected from nominal line-to-neutral voltage multiplied by the product of the regulation factor 1.05 and the voltage rise factor 1.2. This is equivalent to 1.25 times nominal line-to-neutral system voltage. For an MOV type arrester, this voltage is compared with the TOV rating of the MOV. Because the MOV arrester is more sensitive to poor grounding, poor regulation, and the reduced saturation sometimes found in new transformers, it is generally recommended that a 1.35 factor be considered for MOVs.

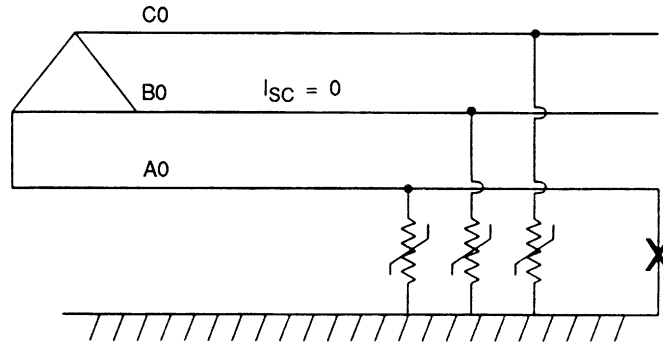


FIGURE 18-27 Line-to-ground fault on a delta system.

A summary of this and other recommendations is as follows:

Open-wire multigrounded system:

$$\text{Rating} = \text{nominal line-to-ground (L-G) voltage} \times 1.25 \text{ (gapped)}$$

$$\text{Rating} = \text{nominal L-G voltage} \times 1.35 \text{ (MOV)}$$

Spacer cable systems:

$$\text{Rating} = \text{nominal L-G voltage} \times 1.5$$

$$\text{Ungrounded rating} = \text{nominal L-G voltage} \times 1.4$$

The temporary overvoltage capability of the arrester as a function of time is shown in Fig. 18-29.

Insulation Coordination

Margins for Overhead Equipment. It is important to note that application of arresters for transmission and distribution is different. In transmission, lightning is of secondary concern in surge

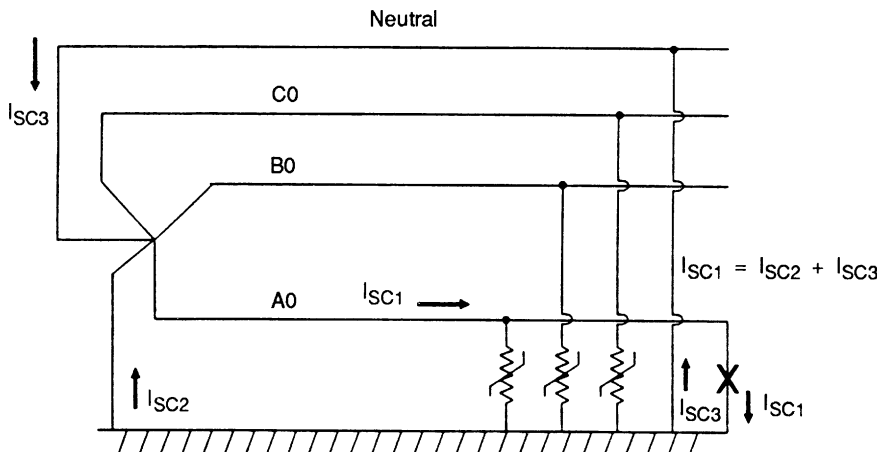


FIGURE 18-28 Line-to-ground fault on a grounded-wye system.

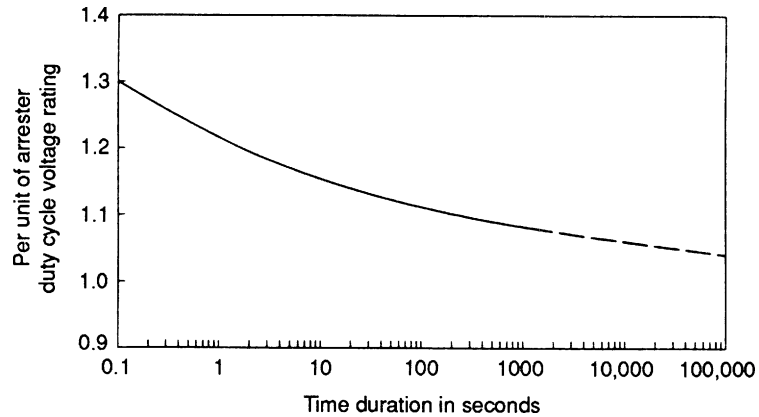


FIGURE 18-29 Example TOV curve (consult arrester manufacturer for exact curve).

arrester application. Primary concern is switching surges. On a distribution circuit, however, the relatively low voltage and short lines tend to make switching surges minimal, and consequently, lightning is of primary importance.

Reflection of this fact can be seen in typical characteristics published for distribution-class arresters, as shown in Tables 18-7 and 18-8. As can be seen, protective characteristics are shown for front-of-wave sparkover and *IR* discharges but not for switching surge waves (as shown for higher rated transmission arresters).

The two protective characteristics normally used for insulation coordination are

Front-of-wave sparkover. This is the first thing that happens to the gapped arrester—it sparks over. It is compared with the fast front equipment insulation characteristics such as the chopped wave insulation level of the transformer. An MOV has no gap but does have an equivalent sparkover, as shown in Table 18-8.

IR discharge at 10 kA. After the arrester sparks over the gap, the lightning current discharges through the block material. Standards recommend that a 10-kA discharge level be used for coordination purposes. (Discharge characteristics across a MOV are very similar to gapped silicon carbide arresters, so the margin calculation is virtually identical.)

TABLE 18-7 Distribution Arrester Characteristics from Handbook—Silicon Carbide

Arrester rating, kV RMS	Maximum ANSI front-of-wave sparkover, kV crest		Maximum discharge voltage, kV crest at indicated $8 \times 20\text{-}\mu\text{s}$ impulse current		
	With disconnector	Externally gapped	5000 A	10,000 A	20,000 A
3	14.5	31	11	12	13.5
6	28	51	22	24	27
9	39	64	33	36	40
10	43	64	33	36	40
12	54	77	44	48	54
15	63	91	50	54	61
18	75	105	61	66	74
21	89	—	72	78	88
27	98	—	87	96	107

TABLE 18-8 Distribution Arrester Characteristics from Handbook—MOV (Heavy Duty)

Arrester rating, kV rms	MCOV, kV rms	Front-of-wave protective level,* kV crest	Maximum discharge voltage, $8 \times 20\text{-}\mu\text{s}$ current wave		
			5 kA	10 kA	20 kA
3	2.55	10.7	9.2	10.0	11.3
6	5.10	21.4	18.4	20.0	22.5
9	7.65	32.1	27.5	30.0	33.8
10	8.40	35.3	30.3	33.0	37.2
12	10.2	42.8	36.7	40.0	45.0
15	12.7	53.5	45.9	50.0	56.3
18	15.3	64.2	55.1	60.0	67.6
21	17.0	74.9	64.3	70.0	78.8
24	19.5	84.3	72.3	78.8	88.7
27	22.0	95.2	81.7	89.0	100.2
30	24.4	105.9	90.9	99.0	111.5
36	30.4	124.8	107.0	116.6	131.3

*Based on a 10-kA current impulse that results in a discharge voltage cresting in 0.5 μs .

Distribution equipment is normally defined as being in a voltage class such as 15 or 25 kV. Most utility equipment is operated in the 15-kV class. A distribution transformer in the 015-kV class is defined by the following insulation characteristics:

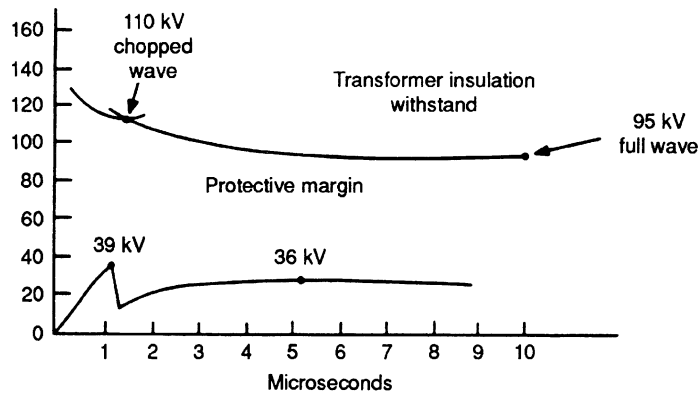
60-Hz, 1-min withstand = 34 kV

Chopped wave (short-time) = 110 kV at 1.8 μs

Basic insulation level (BIL) = 95 kV

Assuming a 12,470-V, 4-wire system (7200 V L-G), we would select the arrester rating based on the rules developed in the preceding section, i.e., a 9-kV arrester (gapped).

We can see from Tables 18-7 and 18-8 that a 9-kV gapped arrester has a sparkover of 39 kV and an *IR* discharge at 10 kA of 36 kV. This could be plotted with the transformer characteristics as in Fig. 18-30.

**FIGURE 18-30** Insulation coordination.

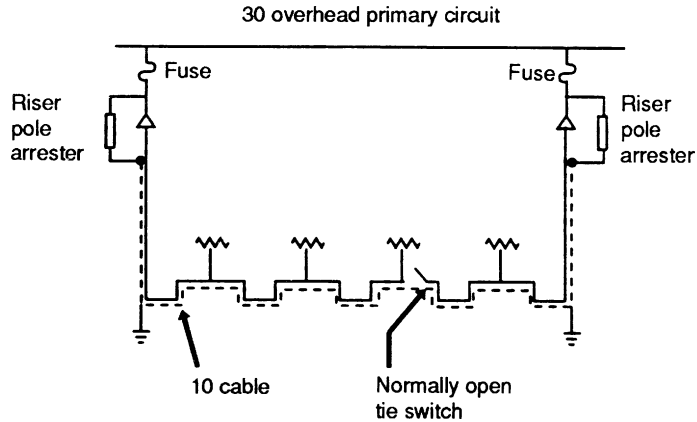


FIGURE 18-31 Underground lateral.

Standards recommend 20% margins calculated by the formula:

$$\text{Margin} = \frac{\text{insulation withstand} - \text{protective level}}{\text{protective level}} \times 100$$

Two margins are calculated, one for the chopped wave and one for the full wave (BIL) of the transformer. These calculations are performed as follows:

$$\text{Margin} = \frac{110 - 39}{39} \times 100\% = 182\% \text{ (chopped wave)}$$

$$\% \text{ Margin} = \frac{95 - 36}{36} \times 100\% = 164\% \text{ (BIL)}$$

As can be seen, these margins (182% and 164%) are greatly in excess of the recommended 20% and consequently show good protection practice. If we were using an MOV, we would simply use the equivalent sparkover or compare only the *IR* discharge and the BIL, since this is the lesser of the two margins. The margins would be similar.

Margins for Underground Equipment If the system is underground, we must be more concerned with the phenomena of traveling waves and the consequent doubling of voltage surges at an open point. For example, a typical underground residential design is shown in Fig. 18-31. A surge entering the cable will travel to the open point where its voltage will double, as shown in the figure, and start on its way back.

This reflected wave plus the incoming waves impose approximately twice the normal voltage on the entire cable and all the equipment connected to it (Fig. 18-32). For example, if we had an arrester with a 36-kV *IR* discharge level (we are only considering BIL margin), we would now expect to see

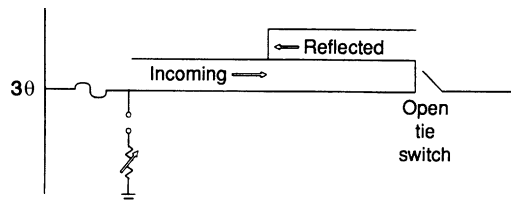


FIGURE 18-32 Reflected surge voltage at open point.

72 kV imposed across the insulation of this equipment. The new margin would then be calculated as follows:

$$\% \text{ Margin} = \frac{95 - 72}{72} \times 100 = 32\%$$

For higher voltage levels, where the margins become considerably less, it may be necessary to use an arrester at the open point or riser-pole arresters having lower discharge levels.

18.11 DISTRIBUTION TRANSFORMERS

Distribution transformers convert electrical energy from primary voltages (2.4 to 34.5 kV) to utilization voltages (120 to 600 V). Momentary drops in lighting voltage caused by the starting current of motors often necessitate use of separate transformers where 3-phase motors 20 hp and larger and 1-phase motors 6.5 hp and larger must be served from radial circuits.

Standard Ratings of Single-Phase Distribution Transformers. By agreement between users and manufacturers, certain features of line-transformer design have been standardized for sizes up to 500 kVA and for voltages up to 67,000 V. Capacities are 10, 15, 25, 37½, 50, 75, 100, 167, 250, 333, and 500 kVA.

Voltage ratings on primary windings are 2400/4160Y, 4800/8320Y, 7200/12,470Y, 12,470GrdY/7200, 7620/13,200Y, 13,200GrdY/7620, 12,000, 13,200/22,860GrdY, 13,200, 13,800GrdY/7970, 13,800/23,900GrdY, 13,800, 14,400/24,940GrdY, 16,340, 24,940GrdY/14,400, 19,920/34,500GrdY, 34,500GrdY/19,920, 22,900, and 34,400. On the secondary side, windings are built for 3-wire operation at voltages of 120/240 or for 240/480. For some of the larger kVA sizes, secondary side windings are available at voltages from 2400 to 7970 V. Bushings for secondary terminals are located on the side of the case, except that primary bushings for 7200 V and higher are cover-mounted.

TABLE 18-9 Typical Electrical Characteristics of Single-Phase and 3-Phase 60-Hz Distribution Transformers
Loss factors can vary according to evaluation factors.

Size, kVA	Percent <i>IR</i>	Percent <i>IX</i>	Percent <i>IZ</i>	Percent no-load loss	Percent load loss
Pole-type single-phase transformers—voltage rating 7200/12,470Y to 120/240 V					
10	1.6	1.4	2.1	0.59	1.65
15	1.3	1.0	1.6	0.51	1.28
25	1.2	1.7	2.1	0.38	1.26
37½	1.3	1.9	2.3	0.37	1.31
50	1.1	1.8	2.1	0.36	1.10
75	1.0	2.1	2.3	0.34	1.03
100	1.0	2.1	2.3	0.32	1.02
167	1.0	2.0	2.2	0.29	0.96
250	1.0	2.3	2.5	0.23	0.99
333	0.9	2.4	2.6	0.21	0.90
500	0.8	2.5	2.6	0.20	0.82
Pad-mounted 3-phase transformers—voltage ratings 12,470Y/7200 to 208Y/120 V					
75	1.0	3.0	3.2	0.52	0.95
112.5	1.1	3.2	3.4	0.40	1.15
150	1.0	3.4	3.5	0.39	0.96
225	1.0	3.4	3.5	0.36	0.98
300	1.0	3.8	3.9	0.33	0.97
500	1.0	3.9	4.0	0.27	0.97

Supporting lugs are arranged to permit mounting either by bolting to the pole or by hanging on crossarms. Where necessary, provision is made for a grounding connection to the case or from the secondary neutral terminal to the case. Similar standards have been promulgated by ANSI for 3-phase pole-type transformers up to 500 kVA.

Electrical characteristics typical of single- and 3-phase transformers of the 12470Y/7200V class are given in Table 18-9. Distribution transformers with different primary voltages will have values only slightly different from those shown in Table 18-9. Transformer regulation for a kVA load of power factor $\cos \theta$, at rated voltage, can be calculated from the formula

$$\text{Percent regulation} = \frac{\text{kVA load}}{\text{kVA transformer}} \left[\% IR \cos \theta + \% IX \sin \theta + \frac{(\% IX \cos \theta - \% IR \sin \theta)^2}{200} \right]$$

Transformers are installed on poles in the following ways: transformers 100 kVA and smaller are bolted directly to the pole, and sizes 167 to 500 kVA have support lugs attached to the transformer and intended for bolting to adapter plates for direct pole mounting or hung on crossarms by means of steel hangers attached securely to the transformer.

Banks of three single-phase transformers are hung side by side on heavy double arms, usually located low on the pole, or on a "cluster" bracket which spaces them around the pole. Three or more transformers 167 kVA and larger are installed on a platform supported by two poles set 10 to 15 ft apart. The transformer-platform structure is often placed on the customer's premises to reduce the distance that secondaries must be run and to avoid pole congestion on public thoroughfares.

Transformers are installed in street vaults, in manholes, on pads at ground level, subsurface, or within buildings. When installed within buildings where the possibility of submersion is remote, the overhead or inside types of transformer and cutout are used. Transformer vaults within a building are of fireproof construction, except when transformers are dry type or filled with nonflammable liquid.

Pole-Mounted Regulators. Today 16- or 32-step regulators built for pole mounting cover the customary $\pm 10\%$ voltage range. Voltage-level control and line-drop compensators give them essentially the same characteristics as the larger station regulators.

Open- Δ connection enables small power customers to receive 3-phase service from two transformers connected to a 3-phase circuit, thus reducing the investment in transformers. Open- Δ from a 3-wire system is the usual Δ connection with one transformer omitted. The connection from a 4-wire system is shown in Fig. 18-33, 2-phase wires and neutral being used on the primary side of the transformers. Current in each of two single-phase transformers connected in open Δ is 73% greater than in each of three transformers connected in closed Δ .

The *Scott connection* shown in Fig. 18-34 gives an accurate transformation but requires one of the transformers to have an 86.6% tap and the other to have a 50% tap.

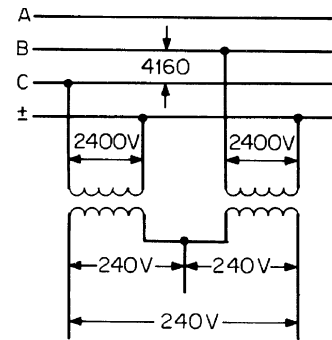


FIGURE 18-33 Open Y connection from 4-wire, 3-phase system.

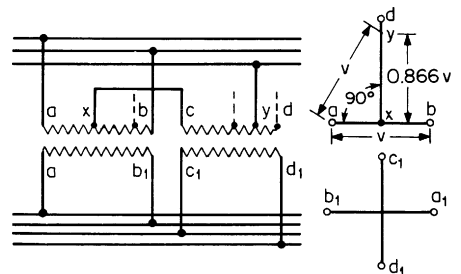


FIGURE 18-34 Balanced T- or Scott-connected transformer connection for 3- to 2-phase transformation.

18.12 SECONDARY RADIAL DISTRIBUTION

Secondary mains operate at utilization voltage and serve as the local distributing main. In early commercial radial systems, secondary mains that supply general lighting and small power are usually separate from mains that supply 3-phase power because of the dip in voltage caused by starting motors. This dip in voltage, if sufficiently large, causes an objectionable lamp flicker.

Single-phase secondary mains supplying general lighting and small power are usually 3-wire mains operating at 120 V line-to-neutral and 240 V line-to-line. Incandescent lamps, fans, heating devices, small fractional-horsepower motors, and other appliances rated 115 or 120 V are supplied from the 120-V line and neutral. Electric ranges, larger single-phase motors up to 6.5 hp, and large appliances rated 230 or 240 V are supplied 240 V. Some utilities supply these loads at 120/208 V.

Three-phase secondary mains are commonly operated 3-wire 240 V. Some utilities offer 208Y/120-V 3-phase 4-wire service. The 3-phase mains are on the same poles or in the same duct line (but in separate ducts) with single-phase lighting mains. Separate single-phase and 3-phase services are extended to customers who require both types of service. In large commercial and industrial installations, power is often delivered at 480 V to effect an economy in conductor investment.

European practice is to supply 230 V to lighting and appliances from a 230/440-V system. This effects a savings in distribution and interior wiring but results in less efficient incandescent lamps and other small appliances.

In America, large commercial buildings and factories are served at 480Y/277 V because most permanent lighting is fluorescent, which operates efficiently at 277 V, and 480 V is well suited for the numerous 3-phase motors. Such installations have small dry-type transformers to supply 120 V for portable lights, convenience outlets, and tools and for business machines; these transformers are located near the 120-V loads and supplied from the 480-V system.

Fractional-horsepower motors up to about $\frac{3}{4}$ hp are regularly supplied by single-phase 120-V mains. Industry committees, sparked by sudden acceptance of home air conditioning, several years ago agreed to permit starting currents not to exceed 50 A for 115-V motors. Special design enabled motors up to $\frac{3}{4}$ hp to meet this limitation. Larger motors up to 6.5 hp are usually served at 240 V, although 3- and 6.5-hp motors may require extra care in distribution design to avoid troublesome flicker. Motors larger than 6.5 hp are usually connected 3-phase. Three-phase service is not usually supplied in residential areas.

Light and Power from One Secondary Main. In a *radial* system, 3-phase service is sometimes supplied from a separate secondary main if voltage is affected by elevator motors or other intermittently used load. If separation of light and power service is not necessary, the nature of the connection may depend upon the relative size of light and power loads. When power load is predominant, lighting load may be served by providing additional capacity in one of the transformers and bringing in a neutral from it for the lighting service. The neutral for lighting service is sometimes derived from a transformer connected to one phase of 240- or 480-V power circuits giving 120/240 V for lighting. This is the usual procedure where power is served at 480 V. When the lighting load is predominant, service is often provided at 208Y/120V, 4-wire.

Transformer and Secondary-Main Economy, Overhead Distribution. Several independent studies have been made to determine the proper combination of transformer and radial secondary main that provides satisfactory voltage regulation and costs a minimum per kVA of load served. All these studies indicate that for 120/240-V single-phase distribution, overhead secondary mains should be three No. 1/0 to three No. 4/0 aluminum, the latter being preferred when air conditioning or heating is to be served.

Permissible length of the three No. 1/0 aluminum secondary mains depends on the load density. On the assumption of evenly distributed loads and 3% drop in the mains, for 15 kW/1000 ft, the

permissible length is 600 ft, and for 30 kW/1000 ft, 400 ft. Widespread use of ranges and motor-driven appliances establishes an additional limit for flicker at 200 to 300 ft.

Transformer size should be such that the initial peak load is between 75% and 100% of rated capacity. In medium-load densities, 25- and 50-kVA transformers will fulfill this requirement. Transformers should be allowed to remain in service until their winter peak load reaches at least 150% to 180% of rated capacity. When this occurs, the “hot spot” winding temperature is approaching 110°C—the maximum safe temperature.

Load growth should be taken care of by *installing additional transformers* and cutting radial secondaries or by *increasing the size* of the existing transformers where secondary-main regulation permits. The three No. 1/0 to 4/0 aluminum single-phase secondary mains should not be replaced by larger conductors to improve secondary-main regulation. Additional transformers should be installed and parts of the existing mains transferred to the new transformers.

Underground systems should also be designed initially with capacity for growth. In order to accomplish this, many utilities in underground residential distribution (URD) work do not use secondary mains. Rather, one transformer is used to supply four to six homes by installing service drops large enough for future loads from the transformer to each home. With this system design it is relatively easy to change out the transformer to a larger size when the load grows.

Pad-mounted transformers can be sized and operated the same as overhead-type transformers. Advantage can be taken of the short-time overload capability given by ANSI C57.91, “Guide for Loading Mineral Oil Immersed Overhead-Type Distribution Transformers with 55C or 65C Average Winding Rise.” Subsurface transformers in close-fitting cylindrical vaults require special baffles and chimney specified by the manufacturer in order that they might be loaded the same as an overhead-type transformer.

Subway-type transformers should not be replaced or relieved of load until the calculated hot-spot winding temperature exceeds 110°C, provided, of course, that voltage at the ends of the secondary is satisfactory. To calculate hot-spot winding temperature, the maximum load and top-oil (or case) temperatures must be measured. Maximum case temperature has been found to be within 3°C of top-oil temperature. It is assumed in making the calculation that the difference between hot-spot-winding and top-oil temperature is 20°C at full load and that this difference varies as the square of load. This is a conservative assumption. For example, assume maximum case temperature 67°C when 130% load is on the transformer. Then the calculated winding hot-spot temperature is given by

$$67^{\circ}\text{C} + 3^{\circ}\text{C} + 20^{\circ}\text{C}(1.30)^2 = 114^{\circ}\text{C}$$

Fans to supplement natural air movement have been used to boost safe capability of vault transformers.

Table 18-10 gives the voltage drop per 10,000 A · ft for single-phase and 3-phase secondaries for a variety of load power factors. The underground portion of the table can be used for underground systems and also overhead systems where triplex cable construction is employed. The overhead part of the table gives the voltage-drop information for overhead aluminum conductors on racks. The table can be used to determine voltage drop quickly on any secondary circuit if load, circuit length, and conductor size are known.

All values in the table are for aluminum conductors at 50°C temperature. Values for copper can be determined with satisfactory accuracy by using the table for a conductor of equivalent resistance; that is, use an aluminum conductor two sizes larger than the copper conductor.

In using the table, the first thing required is the number of ampere-feet involved in the problem. This is obtained by multiplying the amperes per phase by length of circuit in feet. (For single-phase, use number of feet between source and load; impedance of return circuit is included in table.) Divide this ampere-feet by 10,000 to determine the multiplier to be used with values in the table. For the proper voltage, conductor size, and power factor, find the voltage-drop factor in the table and multiply by the multiplier determined previously. This will be the absolute line-to-neutral volts difference (drop) between the sending and receiving ends of the circuit. Dividing by the line-to-neutral voltage

TABLE 18-10 Voltage Drops per 10,000 A · ft* for Single-Phase and 3-Phase Secondaries, 60 Hz

Conductor size	Voltage									
	120/240-V single-phase					208Y/120 V, 240 V, 480Y/277 V, and 480-V 3-phase				
	Lagging power factor									
	0.7	0.8	0.9	0.95	1.00	0.7	0.8	0.9	0.95	1.00
Underground or triplex secondary [‡]										
Aluminum:										
No. 2	4.524	5.042	5.530	5.752	5.858	2.262	2.521	2.765	2.876	2.929
No. 1	3.690	4.084	4.450	4.606	4.646	1.845	2.042	2.225	2.303	2.323
No. 1/0	3.002	3.304	3.574	3.686	3.684	1.501	1.652	1.787	1.843	1.842
No. 2/0	2.458	2.684	2.880	2.954	2.920	1.229	1.342	1.440	1.477	1.460
No. 3/0	2.028	2.194	2.334	2.380	2.318	1.014	1.097	1.167	1.190	1.159
No. 4/0	1.684	1.804	1.898	1.920	1.840	0.842	0.902	0.949	0.960	0.920
350 kcmil	1.166	1.218	1.238	1.228	1.114	0.583	0.609	0.619	0.614	0.557
Overhead secondary [‡]										
Aluminum:										
No. 2	5.530	5.888	6.146	6.192	5.860	2.801	2.974	3.095	3.112	2.930
No. 1/0	3.932	4.088	4.150	4.102	3.700	2.002	2.074	2.097	2.067	1.850
No. 2/0	3.372	3.456	3.448	3.368	2.940	1.722	1.758	1.746	1.700	1.470
No. 4/0	2.516	2.504	2.406	2.284	1.840	1.294	1.282	1.225	1.158	0.920
336.4 kcmil	1.940	1.876	1.792	1.594	1.160	1.006	0.968	0.918	0.813	0.580
477 kcmil	1.646	1.556	1.392	1.248	0.820	0.858	0.808	0.718	0.640	0.410
795 kcmil	1.336	1.224	1.042	0.892	0.480	0.704	0.642	0.543	0.462	0.240

Note: 1 in = 25.4 mm; 1 ft = 0.3048 m. Regulation of copper conductors can be estimated with reasonable accuracy the same as that of aluminum conductors two sizes larger.

*Values in the table give the difference in absolute value between sending-end and receiving-end line-to-neutral voltages of balanced 3-phase circuit and phase-to-phase or phase-to-neutral voltages of single-phase circuit.

[†]Underground cable impedances are based on 50°C conductor temperature with close triangular spacing of cable using typical solid-dielectric insulation, 100% insulation level, single conductor.

[‡]Overhead conductor impedances are based on 50°C conductor temperature with 8-in equivalent spacing for single-phase and 10-in spacing for 3-phase.

of sending end or receiving end and multiplying by 100 will express this as a percentage of sending- or receiving-end voltage, respectively.

Example. Given a 3-phase 60-Hz secondary 500 ft in length, which consists of No. 4/0 aluminum conductor cable; conductor temperature 50°C; receiving-end load 100 kVA at 0.8 power factor lagging; receiving-end line-to-line voltage 480.

$$A \cdot ft = \frac{100}{\sqrt{3} \times 0.48} \times 500 \text{ ft} = 60,142, \text{ or } 6.014 \text{ times tabular value}$$

From Table 18-10 for No. 4/0 cable, 0.8 of the value is 0.902. Line-to-neutral voltage drop is $0.902 \times 6.014 = 5.425$. This is $5.425/277 \times 100 = 1.96\%$ voltage drop on basis of receiving end.

18.13 BANKING OF DISTRIBUTION TRANSFORMERS

Banking. Tying together the secondary mains of adjacent transformers supplied by the same primary feeder is known as *banking*. The practice of banking, when used, is usually applied to the secondaries of single-phase transformers, and all transformers in a bank must be supplied from the

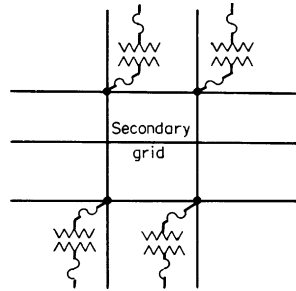


FIGURE 18-35 Fuse application in grid systems.

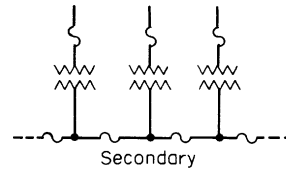


FIGURE 18-36 Fuse application in straight-line systems.

same phase of the primary circuit. The use of banking is not as prevalent as it was formerly. Banked distribution transformers differ from the low-voltage ac network in that one circuit supplies all transformers where secondaries are banked together, whereas different circuits supply adjacent transformers in an ac low-voltage network. Only a few companies operate their transformers banked.

Advantages claimed for banking compared with secondary radial distribution are (1) reduction in lamp flicker caused by starting motors; (2) less transformer capacity required because of greater load diversity among a larger group of customers; (3) better average voltage along the secondary; and (4) greater flexibility for load growth. There are two general types of secondary banking: the grid type and the straight-line type, as shown in Figs. 18-35 and 18-36.

18.14 APPLICATION OF CAPACITORS

Power Factor Correction. It is desirable to add shunt capacitors in the load area to supply the lagging component of current. The cost is frequently justified by the value of circuit and substation capacity released and/or reduction in losses. Installed cost of shunt capacitors is usually least on primary distribution systems and in distribution substations.

The application of a shunt capacitor to a distribution feeder produces a uniform voltage boost per unit of length of line, out to its point of application. Therefore, it should be located as far out on the distribution system as practical, close to the loads requiring the kilovars. There are some cases, particularly in underground distribution, where secondary capacitors are economically justified despite their higher cost per kilovar.

Development of low-cost switching equipment for capacitors has made it possible to correct the power factor to a high value during peak-load conditions without overcorrection during light-load periods. This makes it possible for switched capacitors to be used for supplementary voltage control. Time clocks, temperature, voltage, current, and kilovar controls are common actuators for capacitor switching.

Capacitor Installations. Capacitors for primary systems are available in 50- to 300-kvar single-phase units suitable for pole mounting in banks of 3 to 12 units. Capacitors should be connected to the system through fuses so that a capacitor failure will not jeopardize system reliability or result in violent case rupture. To ensure that the proper fuse protection is provided, the installed capacitor fuse ratings are listed in Tables 18-11 and 18-12 and the probability of rupture is shown in Table 18-13.

TABLE 18-11 Recommended Group Fusing, K- or T-Rated Links (Floating-Y Banks)

Volts	3-Phase kilovar										
	150	300	450	600	900	1,200	1,350	1,800	2,400	2,700	3,600
2,400	40K	—	—	—	—	—	—	—	—	—	—
4,160	25	40	65 ^{a,b}	80K ^{a,d}	—	—	—	—	—	—	—
4,800	20	40	50 ^c	—	—	—	—	—	—	—	—
7,200	12	25	40	50K ^c	80 ^{a,e}	—	—	—	—	—	—
8,320	12	25	30	40	65 ^f	80K ^h	—	—	—	—	—
12,470	8	15	25	30	50 ^g	65 ⁱ	65 ^a	80K ^j	—	—	—
13,200	8	15	20	25	40	50	65 ^a	80K ^j	100K ^{a,k}	—	—
13,800	6	12	20	25	40	50	65 ^a	80 ^k	100K ^{a,k}	—	—
14,400	6	12	20	25	40	50K	65 ^a	80 ^k	—	—	—
20,800	—	8	12	20	25	40	40	50	65	80 ^a	100K ^a
21,600	—	8	12	15	25	30	40	50	65	80 ^a	—
23,000	—	8	12	15	25	30	40	50	65	80T ^a	—
23,900	—	8	12	15	25	30	30	50	65	65	80K
24,900	—	8	12	15	25	30	30	50	65 ^j	65	80K
34,500	—	—	8	10	15	20	25	30	40	50	65

Notes: Fusing is in safe zone unless otherwise shown. Max bank size for 50 kvar units is 600 kvar. Max bank size for 100 kvar units is 1200 kvar. Max bank size for 150 kvar units is 1800 kvar. Max bank size for 200 kvar units is 2400 kvar.

^aZone 1.

^b150-kvar units only.

^cZone 1 for 50-kvar units.

^d200-kvar units only.

^e300-kvar units only.

^fZone 1 for 100- or 150-kvar units.

^gZone 1 for 100-kvar units.

^hZone 1 with 200-kvar units. Not suitable for 100-kvar units.

ⁱZone 1 for 100- and 200-kvar units.

^jFor 200-kvar and larger only, zone 1 for 200 kvar units.

^kFor 300-kvar and larger only.

Effect of Shunt Capacitors on Voltage. Proposed permanently connected capacitor applications should be checked to make sure that the voltage to some customers will not rise too high during light-load periods. Switched capacitor applications should be checked to determine that switching the capacitor bank on or off will not cause objectionable flicker. The curves in Fig. 18-37 can be used to compute voltage rise.

Effect of Shunt Capacitors on Losses. The maximum loss reduction on a feeder with distributed load is obtained by locating capacitor banks on the feeder where the capacitor kilovars is equal to twice the load kilovars beyond the point of installation. This principle holds whether one or more than one capacitor bank is applied to a feeder.

Capacitor kilovars up to 70% of the total kilovar load on the feeder can be applied as one bank with little sacrifice in the maximum feeder-loss reduction possible with several capacitor banks. A rule of thumb for locating a single capacitor bank on a feeder with uniformly distributed loads is that the maximum loss reduction can be obtained when the capacitor kilovars of the bank is equal to two-thirds of the kilovar load on the feeder. This bank should be located two-thirds of the distance out on the distributed feeder portion. Deviation of the capacitor bank location from the point of maximum loss reduction by as much as 10% of the total feeder length does not appreciably affect the loss benefit. Therefore, in practice, in order to make the most out of the capacitor's loss reduction and voltage benefits, it is best to apply the capacitor bank just beyond the optimum loss-reduction location.

TABLE 18-12 Recommended Group Fusing, K- or T-Rated Links
Grounded-Y- and Δ - Connected Banks

Volts	3-Phase kilovar										
	150	300	450	600	900	1,200	1,350	1,800	2,400	2,700	3,600
2,400	40	80	—	—	—	—	—	—	—	—	—
4,160	25	50	80	100	—	—	—	—	—	—	—
4,800	20	40	65	80	140	—	—	—	—	—	—
7,200	15	30	40	65	80	—	—	—	—	—	—
8,320	12	25	40	50	80	100	—	—	—	—	—
12,470	8	15	25	40	50	65	80	100	140	—	—
13,200	8	15	25	30	50	65	80	100	140	—	—
13,800	8	15	25	30	50	65	65	100	140	140	—
14,400	8	15	20	30	40	65	65	80	140	140	—
20,800	6	10	15	20	30	40	50	65	80	100	140
21,600	6	10	15	20	30	40	40	65	80	80	140
23,000	6	10	15	20	25	40	40	50	80	80	100
23,900	6	8	12	20	25	40	40	50	80	80	100
24,900	6	8	12	15	25	40	40	50	65	80	100
34,500	6	6	10	12	20	25	25	40	50	50	80

Notes:

1. Refer to Table 18-13 for fuse sizes within fault current limits.
2. Maximum link size for each unit—check Table 18-9 for all:

50 kvar	65K, 30T	Check Table 18-3
100 kvar	80K, 50T	Check Table 18-3
150 kvar	100K, 50T	Check Table 18-3
200 kvar	100K, 65T	Check Table 18-3
300 kvar and up	140K, 80T	Check Table 18-3
3. Ratio of fuse continuous current rating to nominal capacitor current is 1.65 minimum.

TABLE 18-13 Coordination Table: Grounded-Y and Δ Connected Banks

Maximum fault current for zone indicated.

Fuse link	50 kvar unit		100 kvar unit		150 kvar unit		200 kvar unit		300 and 400 kvar unit	
	Safe zone	Zone 1	Safe zone	Zone 1	Safe zone	Zone 1	Safe zone	Zone 1	Safe zone	Zone 1
30 K and lower	2900	3900	4000	5300	4600	6300	5400	7000	5800	7000
40 K	2700	3900	4000	5300	4600	6300	5400	7000	5800	7000
50 K	2000	3700	3900	5300	4600	6300	5400	7000	5800	7000
65 K	—	2400	2800	5300	4000	6300	5400	7000	5800	7000
80 K	—	—	700	3500	2200	5500	4100	7000	5000	7000
100 K	—	—	—	—	—	2800	1700	6300	2800	7000
140 K	—	—	—	—	—	—	—	1800	—	3500
20 T and lower	2900	3900	4000	5300	4600	6300	5400	7000	5800	7000
25 T	2200	3900	4000	5300	4600	6300	5400	7000	5800	7000
30 T	800	2800	3200	5300	4200	6300	5400	7000	5800	7000
40 T	220	1000	1700	4300	3000	6300	4500	7000	5600	7000
50 T	—	200	400	2500	1100	4000	2800	7000	4200	7000
65 T	—	—	—	500	—	2100	1600	5500	2500	6800
80 T	—	—	—	—	—	—	—	3500	1000	5000
100 T	—	—	—	—	—	—	—	—	—	2200

Note: Safe zone—rupture probability less than 10%. Zone 1—rupture probability 10% to 50%.

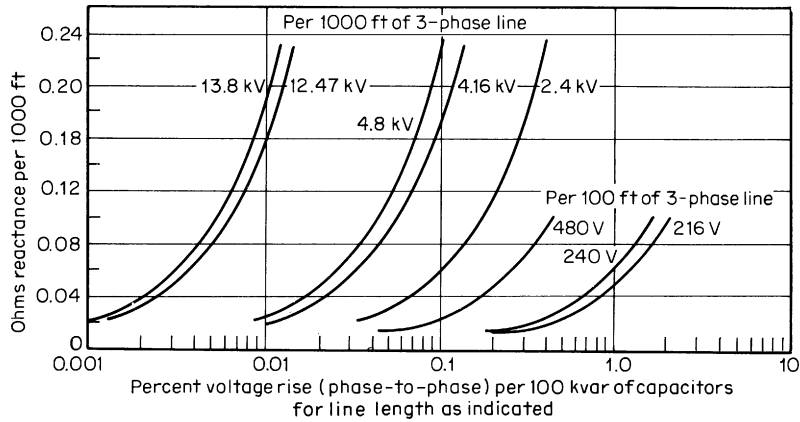


FIGURE 18-37 Curves of voltage rise caused by capacitor application.

18.15 POLES AND STRUCTURES*

Overhead Construction. Although overhead distribution construction remains less costly than underground, the vast majority of *new* residential developments are being served by underground systems. However, most new main feeder circuits and rural and semirural systems are being constructed overhead. Also, because of the tremendous amount of overhead distribution plant already in place, it is important to have a good grasp of overhead construction.

Appearance Considerations. For many years, the traditional overhead distribution construction embodied one or more crossarms on each pole for mounting primary insulators, distribution transformers, surge arresters, cutouts, etc. However, back in the early 1960s when public interest in appearance made itself manifest, many new concepts in overhead construction were introduced in the interest of obtaining better-appearing systems. The principal change was the introduction and wide use of “armless” construction wherein insulators and equipment are directly mounted to the poles. Other ideas also were introduced, such as use of shorter poles, cabled secondaries and services, strategic use of steel poles to reduce or eliminate need for guy wires, and fewer circuits per pole. It should be noted, however, that cabled secondaries employ a “covered conductor” which can withstand momentary contact between conductors but which is appropriately considered by the National Electrical Safety Code ANSI C2 to be the same as bare conductor for clearances to other objects and for all other purposes. In addition, the black covering adds both thickness and contrast to the cables when viewed against the sky.

Wood poles have been used almost universally for overhead distribution lines because of the abundance of the material, ease of handling, and cost. The life of wood poles is materially extended with wood preservatives, and cedar, pine, and fir are most commonly used.

Specifications and dimensions for wood poles are presented in ANSI O5.1. Poles meeting the requirements of this standard are grouped into classes based on their circumference at a location 6 ft from the butt. Poles of a given class and length are designed to have approximately the same load-carrying capacity regardless of species. ANSI O5.1 used a uniform methodology for testing poles that

*To avoid inappropriate duplication, certain discussions common to transmission and distribution may be found in Sec. 14.

required a uniform fulcrum-point location. This point generally was 2 ft plus 10% of the length of the pole measured up from the butt of the pole. This same value has been used as a setting depth for many locations but is not sufficiently deep for some soils.

The minimum circumferences specified at 6 ft from the butt have been calculated in order for each species in a given class to develop, at the ground line, appropriate stresses when a given horizontal load is applied 2 ft from the top of the pole. The horizontal loads used in the calculations for identifying the 15 classes are as given in Table 18-14.

In making the calculations, it was assumed that the pole is used as a simple cantilever and that the maximum fiber stress in the pole due to the bending moment will occur at the ground level. The circumference at the ground line was calculated using standard engineering formulas. This circumference value was then used to calculate the circumference 6 ft from the butt using typical tapers per foot of length between the ground line and the point 6 ft from the butt.

The assumption of maximum fiber stress at the ground line is theoretically correct if the taper of the pole is such that the circumference at the ground line is not more than $1\frac{1}{2}$ times the circumference at the point of loading. If the circumference at ground line is more than $1\frac{1}{2}$ times the circumference at the point of loading, the maximum fiber stress theoretically occurs at a location above the ground line where the circumference is $1\frac{1}{2}$ times the circumference at the point of loading. This makes it necessary to calculate specific loads supported.

Typical tapers used in determining the required circumference 6 ft from the butt circumference range of 0.38 for western cedar to 0.20 for western hemlock. These numerical values are in change in circumference per foot of length.

Concrete poles reinforced with steel originally were employed chiefly for street-lighting standards, where a neat appearance is demanded. But some concrete poles have been used for general distribution as well, usually with a minimum of attached wires and apparatus.

With the increased manufacturing and quality control capability for prestressed concrete poles, and the need for tall structures for narrow rights of way or aesthetic requirements, has come the more frequent use of prestressed concrete poles in transmission lines. As demands for transmission facilities in urban narrow rights of way have increased, they have been most often met with steel single-pole structures, especially where two circuits are required.

Steel poles, ordinarily set in concrete, have long been used to support street lights. More recently, in a more ornamental form and bolted to concrete foundations, they have been used for parkway lighting and, to a limited extent, for distribution where appearance demands.

Aluminum poles also are employed for parkway lighting standards and for certain other locations. They are bolted to concrete foundations to avoid the attack of fresh cement on aluminum. Although use of aluminum on transmission lines has increased, it has been with latticed structures, not generally with poles.

Types of Loading. Poles carrying overhead distribution lines are subject to vertical and horizontal forces, of which some are continuous and others are applied only under abnormal or occasional conditions. Normal vertical forces are the weight of wires, transformers, and other equipment, and these are less than normal horizontal forces in many cases. Abnormal vertical load is imposed when wires are coated with ice, which may increase their normal weight 200% to 400%. For example, the weight of six covered No. 6 copper wires 100 ft long is normally 67 lb, but ice to a radial thickness of 0.5 in increases their weight to about 370 lb.

TABLE 18-14 Loads Used to Identify Pole Classes

Pole class	Horizontal load, lb
H6	11,400
H5	10,000
H4	8,700
H3	7,500
H2	6,400
H1	5,400
1	4,500
2	3,700
3	3,000
4	2,400
5	1,900
6	1,500
7	1,200
8	740
10	370

Note: 1 lb = 0.4536 kg.

Normal horizontal forces acting on a pole are the unbalanced component of wire tension at turns and corners, the side pull of service drops, and the horizontal component of weight when the pole is not vertical. Abnormal horizontal stresses are imposed by wind pressure, by breakage of conductors, or by failure of supporting guys.

Application of Loading. Vertical loading of wires and equipment is applied through crossarms and other attachments to the pole. These forces are amply sustained by poles chosen to meet requirements of transverse forces, except that for line transformers, poles having 1-in greater diameter than line poles may be chosen. Transverse forces from unbalanced conductor tension at corners and bends are normally the greatest forces acting on the line. These are usually carried by guy cables secured to suitable anchorages, which relieve the pole itself of the stress. In some cases, the pole is underbraced and carries the entire load.

Ice Loading. When wires are loaded with ice, conductor tension is increased in direct proportion to the added weight of ice and may become two to four times as great as normal. This stress is borne by the conductors and, through them, communicated to the pole and the guying system. Where ice loading occurs, the guying system must have a suitable factor of reserve to meet abnormal loadings. The tension of conductors being increased with ice loading, elasticity in the wire permits a slight increase in length which makes tension less than the calculated amount for nonelastic conductors and supports.

Wind Loading. Loading due to wind pressure becomes appreciable in the design of poles and structures when wind velocities of over 40 mi/h are prevalent. Such forces are most noticeable on overhead lines when the direction of wind is at right angles to the direction of wires, both because the area exposed is greatest at that angle and because the force exerted is sustained by the pole without the aid of guying.

The area of conductors exposed to wind is much increased by a coating of ice, and the combination of ice with high wind is often the most severe loading condition to which a line is subjected. In many parts of the United States such a condition is never experienced, and it is very rare even where ice coatings occur almost every winter, since the conductor movement due to wind tends to break off the ice coating.

However, with the introduction of large-diameter conductors and bundled-conductor configurations, high winds in summer or other storm periods not involving ice may cause the greater problem. As a result, the NESC requires that severe wind conditions be checked if any portion of the structure or conductors exceeds 60 ft above grade.

Strength of Wood Poles. The strength of a wood pole must be sufficient to withstand transverse forces such as wind pressure on the pole and conductors, unbalanced pull on conductors when they are broken, and side pull on curves and corners where guys cannot be provided. These forces place the fiber on the wood under tension, and the load which a pole will carry is determined by the inherent strength of its wood fiber under tension and the moment of forces. The moment is

$$M = PL + P_1L_1 + P_2L_2 + \dots \quad (18-13)$$

in which P = force, lb, acting at one crossarm, L = height, ft, at which the arm is attached, P_1, P_2 , etc. = forces acting on other arms, and L_1, L_2 , etc. = respective heights. If s = fiber stress, lb/in², and c = circumference at the ground, in, the allowable moment of a pole of given size is

$$M = 0.00026386sc^3 \quad (18-14)$$

Thus, for a pole having a ground-line circumference of 40 in and an allowable fiber stress in an emergency of 2500 lb/in², the maximum allowable moment is

$$M = 0.00026386 \times 2500 \times (40)^3 = 42,218 \text{ lb} \cdot \text{ft}$$

If the average height of attachments is 30 ft, total force is $42,200/30 = 1407$ lb.

The ultimate fiber stresses for various species of wood poles are listed in ANSI 05.1. In practice, the actual pole stresses are limited to some allowable percentages of ultimate stress. The NESC, provides guidelines for allowable stresses under vertical and transverse loading. The National Weather Service now records wind data that include gust speeds. Consult the latest *NESC Handbook* for requirements in effect at the time of line design. Some utilities use larger factors of safety in their designs to allow for errors in tensions, nonuniformity of soils, or special loading requirements; different factors of safety may be used for normal unbalanced forces and for abnormal forces of a temporary nature.

When the maximum fiber stress is above the ground line because of taper of the pole, the allowable moment can be calculated in a manner similar to Eq. (18-14) using the circumference of the pole at the point of load application and the taper of the pole to determine the location where the circumference is $1\frac{1}{2}$ times that at the location at the load. Usually decay is greatest at the ground line, and as the pole ages, its ground-line circumference is reduced to make it the point of greatest fiber stress.

Example of Calculation of Pole Size. ANSI 05.1 specifies a value of ultimate fiber stress for western cedar of 6000 lb/in². Assume a 40-ft pole and a depth of setting of 6 ft. Assume the pole will carry a transverse pull of 400 lb at a height of 32 ft and another of 90 lb at 30 ft. What class of pole is required and what are its circumferences at ground line and at top?

$$M = PL + P_1L_1 = 400 \times 32 + 90 \times 30 = 15,500 \text{ ft} \cdot \text{lb}$$

If a factor of safety of 4:1 is used with respect to the ultimate stress, the allowable fiber stress is $6000/4 = 1500 \text{ lb/in}^2$. From Eq. (18-14),

$$\begin{aligned} c &= \sqrt[3]{\frac{M}{0.00026386s}} = \sqrt[3]{\frac{15,500}{0.00026386 \times 1500}} \\ &= \sqrt[3]{39,162} = 33.96 \text{ in at the ground line} \end{aligned}$$

From ANSI 05.1, Table 5, this corresponds very closely to a Class 5 pole, which has a circumference of 34.0 in (10.82 in diameter) at 6 ft from the butt. Minimum circumference of this class of pole at the top is 19 in (6.05 in diameter).

If the allowable fiber stress were increased to one-half the ultimate (factory of safety = 2), the moment could be increased to

$$M = 0.00026386 \times 3000 \times (34)^3 = 31,112 \text{ ft} \cdot \text{lb}$$

If this were a northern white cedar pole, having an ultimate fiber stress of 4000 lb/in² and a safety factor of 4, the ground-line circumference would be

$$\begin{aligned} c^3 &= \frac{15,500}{0.00026386 \times 1000} = 58,743 \text{ ft} \cdot \text{lb} \\ c &= \sqrt[3]{58,743} = 38.87 \text{ in} \end{aligned}$$

From Table 3 of ANSI 05.1, this is very close to the Class 5 pole, which has a specified circumference of 39 in 6 ft from the butt. This also illustrates that the pole classification, in effect, defines the loading capability of the pole regardless of the species.

Wind Pressure. Wind pressure must be taken into account when designing a pole line. For purposes of calculation, the following formulas are often used to calculate pressures due to wind:

$$P = 0.004V^2 \quad (18-15)$$

where P = pressure, lb/in², on flat surfaces normal to the wind, and V = wind velocity, mi/h

$$P = 0.0025V^2 \quad (18-16)$$

for cylindrical surfaces such as wires and poles. Values of V can be obtained from weather bureau records for the particular locality.

Wind pressure on a 40-ft pole, of which 34 ft is above ground, with 7 in top diameter and 14 in butt diameter, can be calculated as follows:

$$\begin{aligned} \text{Projected area} &= [(7 + 14) \times \frac{1}{2}] \times 34 \times 12 = 4284 \text{ in}^2 \\ &= 4284/144 = 29.75 \text{ ft}^2 \end{aligned}$$

A wind of 60 mi/h would cause a force calculated by Eq. (18-16):

$$P = 0.0025 \times (60)^2 = 9.0 \text{ lb/ft}^2$$

Since the uniform wind pressure is applied to a long, slender trapezoidal area whose center of gravity is 15.11 ft above the ground line, the resulting moment about the ground line is

$$9 \times 29.75 \times 15.11 = 4046 \text{ ft} \cdot \text{lb}$$

With the diameter of a typical distribution conductor taken as about 0.35 in, the total wind force on a 150-ft span assuming 60 mi/h would be

$$\left(150 \times \frac{0.35}{12}\right) \times 0.0025 \times (60)^2 = 39.375 \text{ lb}$$

On six conductors it would be 236.25 lb. Assuming that the conductors have an effective height of 31 ft at the pole, the resulting moment is $236.25 \times 31 = 7324 \text{ ft} \cdot \text{lb}$. The sum of the moments from wind pressure on pole and wires is

$$4046 + 7324 = 11,370 \text{ ft} \cdot \text{lb}$$

When distribution transformers, capacitors, voltage regulators, or other equipment are mounted on the pole, resulting wind forces should be taken into consideration.

In some areas where (1) overhead facilities are subject to high winds; (2) the soil is such as to provide relatively poor overturning resistance; and (3) underground facilities are inappropriate, such as barrier islands subject to hurricane and tidal forces, a unique system is employed to provide for minimum storm damage and quick return to service. In these cases, the structures are deliberately overdesigned relative to their natural foundations so that they will lean, rather than break, under excessive wind loading. Power is turned off as winds reach hurricane speed. After the storm, the lines are inspected, leaning poles are straightened, and service is restored, all with a minimum outage time and expense.

Ice- and wind-loading requirements vary widely throughout the United States, and each utility has adopted design practices suitable for its own conditions of terrain and climate. The NESC, presents some guidelines on conductor loading.

The actual loading on conductors is equal to the resulting loading per foot due to the vertical load on the conductor, assumed ice-covered where appropriate, and the transverse loading due to horizontal wind pressure on the projected area of the conductor, again assumed ice-covered where appropriate. Usually a design constant is added to the loading so calculated.

To establish the guidelines for the loading of overhead lines, the NESC has divided the United States into three loading districts, heavy, medium, and light. These are roughly (1) the northeastern section extending east to west from the Atlantic through the Dakotas and from the Canadian border southward into Texas and the Ohio Valley; (2) the Pacific Northwest and a narrow belt eastward to the Atlantic including parts of Arizona, Texas, Louisiana, Alabama, Georgia, and the Carolinas; and (3) the remaining narrow belt extending from coast to coast and bordered on the south by Mexico and the Gulf of Mexico. These are, respectively, the heavy, medium, and light loading districts.

TABLE 18-15 Conductor Loadings Due to Ice and Wind

	Loading district			
	Heavy	Medium	Light	Extreme wind loading
Radial thickness of ice, in	0.50	0.25	0.00	0.00
Horizontal wind pressure, lb/ft ²	4	4	9	9 to 31
Temperature, °F	0	+15	+30	+60
Constant to be added to the resultant, lb/ft	0.30	0.20	0.05	0.00

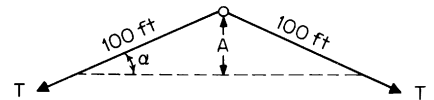
Note: 1 lb/ft = 1.488 kg/m; 1 lb/ft² = 4.882 kg/m²; $t_c = (t_F - 32)/1.8$. Selected data from the National Electrical Safety Code, IEEE C2-1997. Since heavy ice does not often form on conductors in a heavy wind, the transverse loading assumed is deemed sufficient for the purpose but is not sufficient to represent the vertical (or combined) load which is imposed on conductors by heavy deposits of ice which frequently form in comparatively still air. In order to apply a total loading to conductors representing more nearly the conditions encountered in practice, constants are added to the conductor loading.

Exact locations of these districts may be found in the *NESC Handbook*. Table 18-15 illustrates suggested loadings. The constant is used only for conductor strength checks. It is not used in applying loads to structures.

Equipment Loading. Poles are subject to heavy loads when used to support equipment such as distribution transformers, voltage regulators, and capacitor banks. Such loads are chiefly vertical but do have a transverse component when the pole is bent or drawn away from a vertical position. The equipment also presents additional transverse loading due to wind pressure. Therefore, poles to be used for supporting equipment usually are specified to be of a better class than those supporting conductors only.

Three-unit installations of distribution transformers normally employ the “cluster-mounting” arrangement in which the transformers are supported directly on the pole by suitable brackets. Three-phase banks as large as 500 and 750 kVA are installed in this manner. The former practice of supporting the transformers on a platform carried by two or more poles has nearly disappeared because of appearance and cost considerations.

Unbalanced Loads. Transverse forces are imposed on a pole where there is a change of direction of the line, that is, where the conductors on either side of the pole form an angle. These forces usually are offset by guys where practicable. The loading on the structure, including guys, is considered to be the resulting load equal to the transverse wind load and the load imposed by the conductors due to the change in direction. If it is not practical to guy, the pole and its setting must have sufficient strength to withstand the stresses imposed. The force applied to the pole at the point of attachment of the conductors can be calculated as in Fig. 18-38. Divergence from a straight line can be determined by joining two points, each 100 ft from the corner pole, by a straight line. The distance A from the corner pole perpendicular to this line can then be used to calculate the transverse force applied by the line wires on the pole.

**FIGURE 18-38** Determining transverse force on a corner pole.

Assume T to be the total tension, in pounds, of all the wires carried by the pole.

$$\text{Transverse force} = 2T \sin \alpha = 2T \frac{A}{100} \quad (18-17)$$

For example, if A is 10 ft, and if there are six wires having a total tension of

$$T = 6 \times 250 = 1500 \text{ lb}$$

the transverse force due to conductor tension to be sustained normally by the pole is

$$2 \times 1500 \times \frac{10}{100} = 300 \text{ lb}$$

For right-angle turns, α is 45° , $\sin \alpha = 0.707$, and $A = 70.7$ ft. This is the most severe condition ordinarily encountered. In such cases, tensions should be reduced as much as practicable at the corner pole by shortening spans and by transferring a part of the stress to guy wires. Stresses at dead-end poles are treated similarly.

Safety-Code Requirements. The National Electrical Safety Code, in Part 2, sets up minimum safety requirements for loading, strength, and clearance for those parts of supply lines which are involved in crossings of railroad or communication circuits or which come into such proximity to these as to create a “conflict.” It also includes joint use of lines and separate use on any public way. The code recognizes differences in degree of estimated hazard, which are assumed to depend on voltage of the supply line, importance of railroad and other communication systems, classification of loading district, types of crossings, etc. The NESC allows reduced loadings where utility facilities are sheltered from the wind, but it requires full loadings to be met if those shelter mechanisms do not exist. Caution is advised in depending on the continued existence of buildings and other artificial objects as a sheltering influence—especially in the case of buildings; they can either (1) be removed or (2) be joined by others and produce channeling effects that would adversely affect the line loading. Similarly, trees are not generally considered to be an effective shelter because of the possibility of clear-cutting or other removal.

18.16 STRUCTURAL DESIGN OF POLE LINES

Pole Location. In residential areas, poles are generally spaced from about 100 to 150 ft apart depending on the size of the lots. The span usually is an integral number of lot widths in length, and poles are set to provide convenient points for connection of services. Longer spans up to 300 ft or longer are used in rural areas. In either case, pole spacing should consider expected future growth and service requirements in the area. The choice of pole spacing is also a function of the load to be carried and the relative economics of longer spans. Pole spacing and line location both are a function of the obstacles in the area. The NESC, ANSI C2, has specific requirements about placement of poles near other poles, roads, buildings, fire hydrants, etc.

Poles are required to be at least 3 ft away from fire hydrants and should be at least 4 ft away. Although these distances are required to allow firefighters access in emergencies, they also give room for personnel working on the pole to move around on the ground. No fire hydrant, telephone pedestal, or other like object should be located on the climbing side of the pole; the climbing side of the pole should be kept clear of protruding obstacles to provide a clear drop zone for line workers if they chip out of the pole and fall.

There are two hazards with the line-worker's gaff cutting out chipping on a pole; the first is the possibility of injury due to picking up splinters from previous gaff marks, and the second is the possibility of injury from the fall. Because of the severe problems caused from splinter injury, some communication line workers (who do not climb as high as supply workers) are taught to climb a pole without belting off until they reach the work height; this allows them to push away from the pole as they go down and allows them to roll when they hit the ground. In such cases, no obstruction should be allowed on the climbing side within 10 ft.

Poles and their supported equipment up to 15 ft above a roadway are required to be located far enough from roadways so that an ordinary vehicle that is using and located on the traveled way will not contact the utility facilities.

Poles are required to be at least 12 ft from railroad rails, except in some limited sidings where the clearance must be 7 ft, and room must be left to unload cars. Where some other facility is the controlling obstruction, the clearance may be reduced from 12 ft but may not be less than 7 ft.

Selection of Poles. The height of poles is determined by required clearances over obstructions, streets, and crossings, the span lengths, and the number and character of conductors or circuits to be carried. The most usual lengths for poles used in distribution construction have been 30, 35, and

40 ft. Armless construction and joint use tend to favor the 40-ft length. In recent years, however, as space for CATV and other facilities is provided on joint-use poles, 45-ft poles are even more commonly used, especially in hilly terrain. The Class 5 and 6 poles are very popular, although larger poles are often required where heavy equipment is to be mounted or longer spans with greater wind loadings are used. The class of pole is determined by stress requirements for the grade of construction being employed.

Where primary conductors are to be carried with joint use, the 35-ft pole usually is the minimum used, and 40 ft is quite common. Without primary conductors and with joint use, 30-ft poles are used occasionally. Joint use of pole lines by two or more public service companies is encouraged where feasible because (1) it makes maximum use of capital investment and avoids undesirable duplication of pole lines, and (2) it provides fewer opportunities for one circuit to fall into another during a storm. When a pole or section of poles is broken as a result of the action of falling trees, flying debris, or errant vehicles, the tendency is for all circuits of a joint-use line to be promptly and automatically deenergized. However, if a conflicting line falls into another line, facilities or personnel working on the other line may be damaged. Thus conflicting line locations are discouraged where joint-use locations are practical. In either case, the NESC, requires greater strengths than for single-circuit installations.

Pole-Setting Depths. Table 18-16 lists typical depths of setting for wood poles of various lengths. These are sufficient for most soils but must be increased for larger poles set in lighter or more fluid soils; these setting depths are based on the fulcrum points used for testing pole strength in ANSI O5.1. They do not vary with pole diameter and may not be sufficient for large poles with large loads.

TABLE 18-16 Depth of Wood-Pole Settings

Length of pole, ft	Depth of setting, ft
30	5.5
35	6
40	6
45	6.5
50	7
55	7.5
60	8
70	9

Note: 1 ft = 0.3048 m.

Guying Longitudinal, Angle, and Dead-End Force with Tensile Guys and Anchors. When the horizontal loads to be carried by poles are greater than can be safely supported by the poles, guys or braces are required to provide additional support. Guys and anchors are commonly used wherever conductor tensions are not balanced, as at dead ends, corners, or where the direction of the line changes substantially. Down guys transmit force from the overhead structure system to a buried anchor system (Fig. 18-39). They are located opposite the forces and use materials in tension to balance the forces. Where it is not practical to place these facilities to continue the imbalanced forces to ground, a compressive guy or pole brace must be used.

Where traffic ways or other obstacles do not allow direct anchoring of the forces at the imbalanced pole, an overhead span guy is used to transmit the force to another pole in line with those forces and in a place that allows a down guy to be used. The best down guy is a straight anchor guy composed of appropriate wire, fastenings, and anchor; it is the most economical to install in most locations, is the least trouble to maintain, deteriorates the least over time, and is the most reliable type of down guy.

The NESC, requires guys to have 4.72 m (15.5 ft) clearance over roadways and 2.89 m (9.5 ft) over spaces or ways accessible to pedestrians only. Where an anchor guy cannot be used because of interference with pedestrian or vehicular traffic, and where there is no practical location for an auxiliary pole and anchor guy that would allow a span guy to be used, a stub guy may have to be used. A stub guy consists of an angled span guy from the imbalanced pole to a short stub pole that is (1) high enough to provide the clearance required for the guy over the affected area and (2) low enough that the resulting moment arm is short enough that the stub can take the forces involved. Often the stub pole will have to be separately braced below ground to take the forces. Obviously, these conditions are not desired, and they are not practical for balancing large forces.

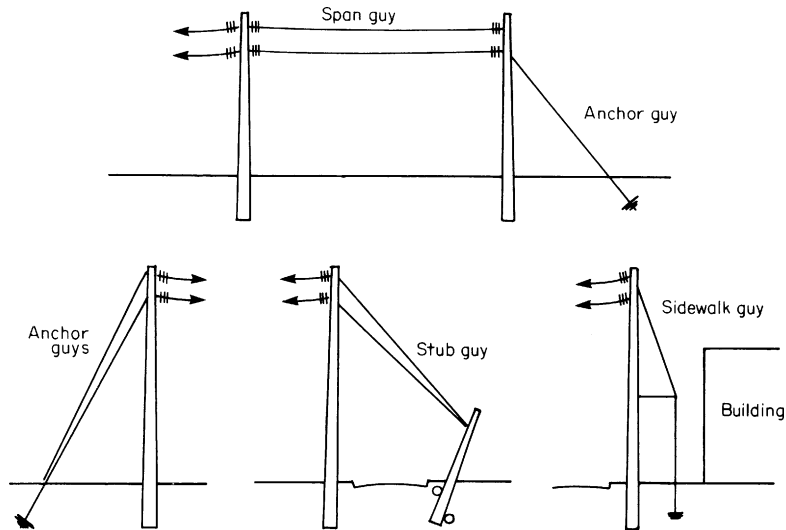


FIGURE 18-39 Tensile guys.

Another down guy used in constrained locations is the sidewalk guy. With the sidewalk guy, a horizontal strut is attached to the pole midway down the pole; the guy wire runs angled from the top of the pole to the strut and straight down to an anchor from there. These guys are most often used to guy small taps off a main line where there is not room for a full-length anchor-guy lead. The strut is usually just long enough to place the anchor back of a sidewalk and high enough to allow pedestrian clearance, hence the name. This guy should not be confused with the compressive guy discussed below; both are sometimes called *strut guys*. Sidewalk guys cannot be used for large forces because they will bow the pole due to their horizontal force; this, in turn, causes serious vertical-loading and bending-moment problems if the forces are great enough.

Where unbalanced tension is experienced by crossarms, such as in sidearm construction or dead ends for heavy conductors, crossarms are often guyed. Often a span guy will be attached to the back of the crossarm at each conductor location and run to another pole in line with the forces; otherwise, excess vertical loading on the crossarms can result.

Guy wires generally are made of stranded steel cable, usually galvanized for weather resistance. Several grades are available, including extra-high strength, which is commonly used. It is available in several diameters in steps of $\frac{1}{16}$ in from $\frac{3}{16}$ in up.

The National Electrical Safety Code, ANSI C2-2002, specifies that guy wires be used so that, with the required assumed loads and overload factors, they will not be stressed beyond 90% of ultimate strength, and for dead ends, not beyond 66.67% of ultimate strength. After the tension has been calculated, the guy cables are selected so that these requirements are met. The anchor guys usually are installed at a distance from the pole not less than one-quarter or more than 1 to $1\frac{1}{2}$ the height of the guy attachment. Generally a 1:1 slope is preferred. This lessens both the tension in the guy wire itself and the vertical component of forces transmitted to the pole. Where steep angles are used for the guy, or where large forces are otherwise involved, the pole size may need to be increased in order to withstand the vertical forces. In poor soils, this can even push the pole into the ground over time, thus decreasing clearances and twisting the pole, the latter because the now-excessive length of the guy allows the pole to move.

Compressive Guys and Pole-Foundation Underbracing. Where poles with imbalanced forces are so located that tensile guys cannot practically be used, either the forces must be taken by a compressive guy or the pole and its foundation must be made strong enough to take the forces by

themselves. A *compressive guy* consists of a pole (or other member capable of taking the imbalanced load) placed at an angle leaning into the imbalanced pole and attached at the top so that it pushes against the force to be balanced. Its common name is a *push guy* for this reason; it is also called a *strut guy* in a few locations—not to be confused with the sidewalk guy. The most common use for a push guy is on the inside of a curve on a mountain road where, in essence, there is no land on the other side of the road in which to place a pole and anchor to use a span guy; span guys are preferred where they are practical because of their relatively simple installation, longer life, and ease of maintenance compared with the push guy. Push guys are difficult to attach to the supported poles, often can only be attached significantly lower than the imbalanced conductors, especially on sharp angles, and require the imbalanced pole to be oversized as a result. It is generally difficult to position the push guy in the ground, or cut it to the right length, so that the imbalanced pole will remain upright under load.

Where poles supporting unbalanced stresses are so situated that it is not practical to support them by either tensile or compressive guying, they must be underbraced to withstand the force imposed with as little deviation from original position as possible. This normally requires that the pole have more than usual diameter and be no taller than absolutely necessary for clearance.

For very long spans or heavy conductors, steel poles are often required. If wood poles are used, top diameters of 8 to 10 in are required for such positions to avoid bending. In addition, the pole is underbraced by timbers bolted to it below ground line and at the butt, as shown in Fig. 18-40. An alternative method, using concrete, is also good. Small boulders or crushed stone may be used in backfill to advantage.

In the use of plank or concrete, the pole is set at a slight angle, or rake, in a direction opposite that from which stress is to be applied, to allow for compacting of soil when wires are pulled up. The area of plank or concrete should be about 4 ft², both top and bottom. Where steel poles are used to secure strength, they are usually set in a concrete base of such dimensions as to bear the stresses imposed.

Vertical Clearances above Grade. Rule 232 of the National Electrical Safety Code, ANSI C2-2002, specifies the vertical clearances that utility wires, conductors, and cables must maintain above railroads, roads and other ground areas, and water areas. Before 1990, these clearances were specified when the conductor was at 15.5°C (60°F) conductor temperature (not ambient air temperature) and at specified ice loadings, whichever produced the greater sag. For span lengths greater than the basic span length applicable for the ice-loading area (heavy, medium, or light) and for conductor temperatures above 49°C (120°F), additional clearances were required.

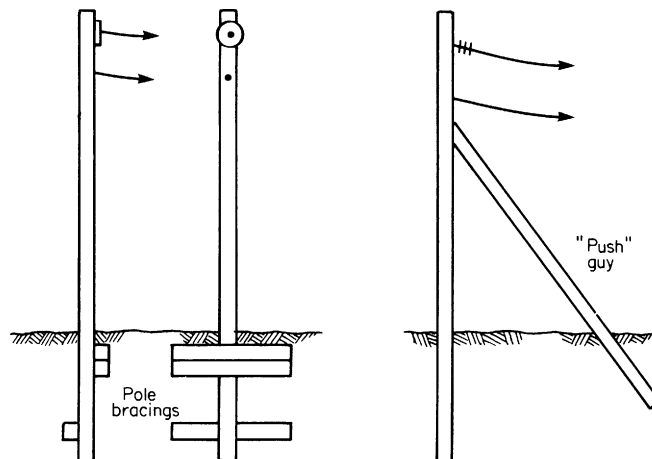


FIGURE 18-40 Comprehensive guy and pole bracing.

In 1990, the National Electrical Safety Code respecified the clearances to apply at maximum-sag conditions and coordinated the clearances with a system of reference dimensions of expected activity under the line and building blocks related to actual or potential voltage levels. For roads, parking lots, and other areas expected to have trucks, the reference dimension is 4.27 m (14 ft). For areas limited to personnel or restricted traffic only, the reference dimension varies from 2.4 to 3.0 m (8 to 10 ft), depending on the expected problem.

The building blocks include 30.42 cm (1.0 ft) for structure arms, 45.72 cm (1.5 ft) for neutrals and communication cables and grounded guys, 0.6 m (2.0 ft) for secondary bushings and jumpers up to 750 V and duplex, triplex, and quadruplex cables with bare neutrals, 0.76 m (2.5 ft) for open (bare or covered) supply conductors up to 750 V, 1.22 m (4.0 ft) for primary voltage bushings up to 22 kV, and 1.37 m (4.5 ft) for primary voltage conductors up to 22 kV. Additional clearances apply above 22 kV or 1 km (3300 ft) above sea level.

The previous 15.5°C (60°F)-based clearance requirements included 0.46 m (1.5 ft) to allow for sag change from 15.5 to 49°C (60 to 120°F) or specified ice-loading conditions. The 5.6-m (18.5-ft) minimum clearance specified in the NESC beginning in 1990 for distribution primary voltage conductors above a road 4.3-m (14-ft) reference dimension plus 1.4-m (4.5-ft) building block produces the same essential clearance requirement as the previous system. Similarly, the minimum clearance for a distribution neutral, guy, or communication cable is 4.7 m (15.5 ft, i.e., 14 + 1.5).

The present system (1) requires the installer to use actual expected changes in sag from the installed sag to the maximum final sag expected; (2) better states the real clearance involved; and (3) does not include the previous clearance penalties for short spans with less than 0.46 m (1.5 ft) of sag change from its 15.5°C (60°F) position.

It is important to stress that the NESC vertical clearances apply when the conductor is at its maximum sag position, even including emergency sag conditions, such as when one power line picks up the load from another line and the line losses heat the conductors above their normal maximum temperature. If special, localized icing conditions apply to the line, they also should be used to determine whether the summer or winter maximum sag conditions will be determinant.

Clearances Between Crossing or Adjacent Wires, Conductors, or Cables Carried on Different Supporting Structures. Where any two wires, conductors, or cables cross or are adjacent in open span without being supported on a common structure, the clearances between them must be sufficient to limit the possibility of contact between them. The effect of movement under wind, thermal, or ice loading must be considered as well as the required clearances between them. The National Electrical Safety Code considers that the two suspended facilities must first be considered to be in their most proximate position relative to each other, assuming that both experience the same ambient conditions (i.e., wind direction and speed, air temperature, and icing conditions); then the distance between them must meet the clearance requirements for the two facilities.

Caution is advised in choosing the most proximate position. The two facilities may move different amounts because of the same wind pressure; one may be unloaded at ambient temperature or fully ice loaded, while the other may be at maximum operating temperature. One could be at initial sag while the other is at final sag. Examination of Rule 233 of the National Electrical Safety Code is recommended.

Determining the closest approach of conductors in winter icing conditions can be confusing. When one line is across the wind and another is with the wind, one loads up with more ice than the other one. In addition, one line can lose its ice before the other one, due to wind or due to thermal loading from line losses. Ice typically forms very near -1.1°C (30°F). If the temperature is significantly colder, the precipitation tends to bounce off rather than coat. However, after the ice has formed, the temperature can fall, bringing with it more heating load and sometimes lighting loads. Thus it is not unusual for an ice-covered conductor to be heated by line losses back up to 0°C (32°F) and eventually melt its ice off. In the meantime, this conductor will be at its maximum sag of 0°C (32°F) with a full coating of ice. The position of the lower conductor for clearances purposes is at the coldest ambient temperature at which the load on the upper conductor could heat it up to 0°C (32°F). This takes care of the cases where the lower conductor has dropped its ice (or was never fully

iced) or the lower conductor has come down and is being replaced (without ice) when the upper conductor is at its maximum sag.

Unless the actual relative icing/heating conditions are known, a practical method of choosing an appropriate mismatch in temperature for the winter icing clearances is to use the temperatures used by the National Electrical Safety Code to determine required strengths as the temperature of the lower conductor without ice when the upper conductor is at 0°C (32°F) with the specified ice loading. They are -9.4°C (15°F) for the medium loading district and -17.8°C (0°F) for the heavy loading district. Detailed examination of Rule 233 of the NESC is recommended.

When the suspended facilities are at their closest proximity, both the vertical clearance and the horizontal clearance should be checked to see which is controlling. The horizontal clearance must be at least 1.5 m (5 ft). Where the voltage potential between them exceeds 129 kV, an additional clearance of 0.4 in/kV is required. The basic vertical clearance when the conductors are closest together is 0.6 m (2 ft), with additional clearances required where higher voltages are involved with communications.

Clearances from Buildings and Other Installations. Wires, conductors, and cables which pass by buildings, signs, supporting structures of a second line, pools, bridges, tanks, etc. are required to have clearances from those structures, when not attached to them, that allow normal use of those facilities. Required clearances are given in the NESC. In general, clearances above portions of structures which are accessible to pedestrians or vehicles are the same or similar to those above ground for the same activity. Where pedestrian access is restricted and the area is normally accessible only to workers, lesser clearances are allowed. Clearances allow normal maintenance of the structures being passed by. The minimum horizontal clearance from energized distribution primary voltage conductors to supporting structures of a second line, lighting support of traffic signal support is 1.5 m (5 ft). The minimum vertical clearance above such supporting structures is 1.37 m (4.5 ft).

The vertical clearance required by the NESC for energized distribution primary voltage conductors above building roofs and projections not accessible to pedestrians is 3.81 m (12.5 ft); this allows workers with hand tools the room to work on the roof. Above signs, this clearance drops to 2.4 m (8.0 ft) for open conductors. Vertical clearances to roofs and balconies accessible to pedestrians and catwalks on signs and tanks cannot be less than 4.1 m (13.5 ft) for the distribution primary voltage conductors. Lesser clearances apply for communication and for supply cables and secondary voltages up to 750 V. Greater clearances apply for higher voltages. Bridges have lesser clearances where workers are allowed and generally the same clearances as buildings where pedestrians are allowed. Greater clearances are required around pools and associated structures to accommodate pool skimmer poles, rescue poles, and diving.

Clearances for Facilities Suspended from the Same Structure. The clearances required by the NESC, between wires, conductors, and cables carried on the same supporting structure provide adequate room on the structure for workers to operate and maintain the lines, adequate room out in the span for communication workers to work under supply facilities, and adequate separation between suspended facilities to limit contact by them during operation. Because some communication cables on longer spans will “gallop” in high winds, and because such cables may gallop as high as a straight line between their points of attachment at supports, supply conductors above 750 V generally are prohibited from sagging lower than such a straight line.

The vertical clearance at supports for primary-supply conductors above other facilities is required to be 16 in above neutrals and 40 in above communication (more if above 8700 V). For supply conductors at voltages up to 8700 between conductors, the minimum horizontal clearance provided by the NESC, is 12 in. For higher voltages it is required that 0.4 in be added for each 1000 V above 8700. For sags of more than 24 in, clearances greater than 12 in are required and are determined by the following formulas, where S = sag, in. For wires of No. 2 AWG or larger,

$$\text{Clearance} = 0.3 \text{ kV} + 8\sqrt{S/12} \quad \text{in} \quad (18-18)$$

For wires smaller than No. 2 AWG, the rule is

$$\text{Clearance} = 0.3 \text{ kV} + 7 \sqrt{S/3} - 8 \quad \text{in} \quad (18-19)$$

Multiconductor, spacer, and other cabled types of supply-circuit construction are exempt from the above phase-spacing requirements.

Climbing Space. Climbing space must be provided on poles for workers to move up and through facilities to reach each of the facilities on the structure unless it is the unvarying rule that workers do not climb the poles. If workers climb some portions of the structure and not others, for example, communication but not supply, and the remainder are worked from insulated bucket trucks, only the portions climbed must have climbing space. The climbing space may move around the pole to allow access to other parts or to avoid traveling through certain locations, as long as full space is allowed

TABLE 18-17 Horizontal Climbing-Space Dimensions
(Voltage-to-Ground)

Supply conductors	Horizontal climbing space, in
0–750 V	24
750 V–15 kV	30
15–28 kV	36
28–38 kV	40
38–50 kV	46

Note: 1 in = 25.4 mm.

to facilitate the turns. These dimensions are intended to provide a clear climbing space of 24 in when the conductors bounding the space are covered with appropriate temporary protective covering. The vertical dimension is 40 in above and below the conductors (60 in if above 8700 V). The National Electrical Safety Code, ANSI C2-2002, specifies the horizontal climbing-space dimensions given in Table 18-17. Where conductors of the same voltage classification are on the same crossarm, the horizontal dimensions are projected vertically not less than 40 in above and below the limiting con-

ductors. Equipment such as transformers, regulators, capacitors, surge arresters, and switches when located below the conductors should be mounted outside the climbing space.

Working Space. Working spaces are required by the National Electrical Safety Code, ANSI C2-2000, at each side of the climbing space and extending to the outermost conductor positions. The size of the working space is linked to the vertical clearances required between conductors at the support and the size of the climbing space, both vertical and horizontal.

Clearances Between Supply and Communication Equipment. The National Electrical Safety Code, ANSI C2-2002, generally requires a minimum of 40-in clearance between supply equipment and communication equipment and between the conductors of each to the equipment of the other. This provides for footroom for the supply workers and headroom for the communication workers. Special provisions are made to allow luminaires to be placed between these facilities.

Vertical and Lateral Conductors. Vertical and lateral conductors may be run within the normal supply space and communication space on a pole if they are so located as to meet the requirements of the National Electrical Safety Code, ANSI C2. Generally such conductors are required to be insulated and placed out of the climbing footroom area or held away from the pole on the opposite side.

18.17 LINE CONDUCTORS

Conductor Factors. Copper and aluminum are the metals most used as conductors in distribution systems. Proportions are fixed by the combined effect of conductivity, weight, strength, and cost. Recent years have seen such a shift in availability and cost that aluminum has gained almost universal use in distribution, supplanting copper, which was preferred for many years.

Conductor Materials. Aluminum has the advantage of about 70% less weight for a given size, but its conductivity is only about 61% that of annealed copper. For distribution, it is commonly rated as equivalent to a copper conductor two AWG sizes smaller, which has almost identical resistance. Its tensile strength is less than copper, and it is commonly used, particularly in the smaller sizes, by stranding aluminum around a steel core of proper size to give the desired tensile strength. In larger sizes, the tensile-strength requirements of distribution are satisfied by stranded aluminum without the reinforcing steel. Another way of obtaining high tensile strength is to combine steel with copper or aluminum wires. Steel is combined with copper in a high-strength strand known as Copperweld, which has 30% to 40% of the conductivity of a copper conductor of equal size. In a similar manner aluminum and steel conductor can be combined into what is known as Alumoweld.

Both copper and aluminum are suitable for use as substation buses, being available in flat bars, tubes, and rods. For very heavy currents, channel shapes are used to make up box-type buses, which are the most economical for such applications.

Use of Copper. Where copper is used for overhead circuits with span lengths of 200 ft or more, it is commonly used in the hard-drawn form because of its greater tensile strength. For common types of local distribution circuit where spans are shorter and flexibility is desirable, medium-hard-drawn, or annealed, copper is used. Mechanical connectors are extensively used for joints and taps on overhead copper.

Underground copper cables are usually made of standard soft copper because of its greater flexibility. The smaller size of copper conductors helps to offset unfavorable price levels because of savings in insulating and sheathing material as well as the ability to put maximum carrying capability in a given size of duct.

Use of Aluminum. In rural line work, where long spans and conductors of high tensile strength are an economic necessity, the combined requirements of conductivity and strength have been met with aluminum stranded around a steel core sized to give the required strength. Such a cable is known as *aluminum cable steel-reinforced* and is commonly designated as ACSR. Development of high-strength aluminum alloys has led to such alternative cables as aluminum conductor alloy-reinforced (ACAR) and all-aluminum-alloy conductor (AAAC), which also combine conductivity with tensile strength. Urban distribution uses ACSR and all-aluminum conductors. Stranded aluminum is common where large conductors are required.

Underground Aluminum Cables. The development of such synthetic insulations as polyethylene has made aluminum almost universally used for underground distribution. In the smaller sizes for URD, a solid conductor is often applied rather than stranded construction. *Jointing of aluminum* requires special care to secure good contact and to guard against corrosion. Jointing is often done with compression devices, although mechanical connectors packed with corrosion-inhibiting compound can be used.

Use of Steel. Steel conductors are rarely used for distribution circuits because of their high resistance. But steel with a heavy covering of copper, known as Copperweld,* or with a heavy covering of aluminum, known as Alumoweld,* has conductivity approaching 40% that of copper and can be used in some applications. Such coated conductors are also very attractive as high-strength strands or reinforcements for composite cables, which get improved conductivity from strands of hard-drawn copper over the Copperweld or hard-drawn aluminum over the Alumoweld.

Conductors reinforced with steel have impedances which increase somewhat as current density increases. Voltage drops are correspondingly higher than those of copper or aluminum conductors of equal conductivity.

Copperweld and Alumoweld are generally more durable than galvanized-steel cables. They have therefore been used to some extent for guy cables. They are also used widely for shield wires.

*Copperweld and Alumoweld are registered trademarks of the Copperweld Bimetallic Group.

18.18 OPEN-WIRE LINES

Crossarms. Southern pine and Douglas fir are the best woods for crossarms because of their thin, straight grain, high tensile strength, and durability. Experience indicates that a cross section $3\frac{1}{2}$ in wide by $4\frac{1}{2}$ in high is ample for the average distribution line. Main lines are commonly built with six-pin arms, and smaller lines use four-pin arms. Minimum spacing of pins is 12 in, and spacings of 14 to 16 in are commonly used. Minimum spacing of pole pins is 30 in to provide climbing space. Crossarms also are used for supporting transformers and other equipment.

Double crossarms are installed on poles at corners, at terminals, and at other points where unusual loads are to be supported. Vertical racks are installed on poles to support secondary and multiple street-lighting wires. They are available with two-, three-, or four-spool insulators. Rack construction is less expensive than crossarms and has supplanted them to a large extent. When services run to houses on both sides of the street, two racks are required, one on each side of the pole. In addition, several pole-top designs mount insulators directly on the pole, eliminating the use of crossarms.

Wire Stringing. In erecting wire, the *tension* should be sufficient to prevent too much sag in the spans and yet not so great as to stress the wire unduly. For practical purposes, the approximate formula given by Rankine may be used:

$$t = S^2 w / 8d \quad \text{lb} \quad (18-20)$$

in which t = tension, lb, S = span length, ft, w = resultant load, including weight of wire, lb/ft of conductor, and d = sag, ft, at the center of a horizontal span. If span length is doubled, tension must be quadrupled in order to keep sag the same. If tension is the same on several spans of different lengths, sag is different in each span. The sag of any span when tension is known is found by changing Eq. (18-20) to the form

$$d = S^2 w / 8t$$

Sag Tables. Maximum tension in a span is limited by the strength of the wire and supports. Conductor sags under the assumed loading conditions for the particular loading district (see National Electrical Safety Code, ANSI C2) should be such that the tension of the conductor should not exceed 60% of its ultimate strength. Also, the tension at 60°F, without external load, should not exceed 35% of the conductor ultimate strength under its initial unloaded condition.

It is not unusual to design so that the tension of the conductor will not exceed 50% of its ultimate strength under loaded conditions or a 2000-lb limitation. In some cases, the same sag values are employed for a range of wire sizes so that the appearance of a line carrying different conductor sizes will be improved. The sags given in Table 18-18 are selected from standard sheets of a large utility.

Expansion and Contraction of Conductors with Temperature Change. Changes in sag due to expansion and contraction of conductors under varying temperature conditions are important in the stringing of conductors. Lines erected in winter months are likely to be too slack during the summer unless allowances are made. The length of wire in a span, elastic stretching due to mechanical loading being disregarded, varies as determined by the coefficient of expansion of the conductor and the temperature range,

$$L_t = L_0(1 + \alpha_0 t) \quad (18-21)$$

where α_0 = coefficient of expansion, ft/ft of length/°F above 10°F

t = temperature, °F (above 0°)

L_0 = length of wire at 0°F

For aluminum: $\alpha_0 = 0.000024/^\circ\text{C}$ or $0.0000133/^\circ\text{F}$

For ACSR: $\alpha_0 = 0.0000112/^\circ\text{C}$ or $0.0000062/^\circ\text{F}$ (nearly that of steel)

For copper: $\alpha_0 = 0.000017/^\circ\text{C}$ or $0.0000094/^\circ\text{F}$

TABLE 18-18 Sags for Typical Distribution Conductors (Heavy-Loading District—60°F)

Size, AWG or M cmils	Conductor material	Sags (in) for span lengths (ft) of							
		80	100	125	150	175	200	250	300
Open wire:									
No. 1/0	Al alloy, bare		10	16	23	31	40	27*	38*
No. 3/0	Al alloy, bare		10	16	23	31	40	32*	46*
336.4	Aluminum, bare		10	16	23	31	40	75	108
No. 1/0	Al alloy, polyeth.		10	16	23	31	40	59*	90*
No. 3/0	Al alloy, polyeth.		10	16	23	31	40	70	101
336.4	Aluminum, polyeth.		18	27	38	51	66		
Cabled secondaries:									
3 No. 1/0	Al alloy, insul.		10	16	23	31	40		
3 No. 3/0	Al alloy, insul.		18	27	38	51	66		
4 No. 3/0	Al alloy, insul.		18	29	43	60	80		
Cabled service drops:									
3 No. 4	Aluminum, insul.	32	52	73†					
3 No. 1/0	Aluminum, insul.	51	79	116†					
4 No. 3/0	Aluminum, insul.	68	108	171†					

Note: 1 in = 25.4 mm; 1 ft = 0.3048 m; 1 lb = 0.4536 kg.

*Taken up to 2000-lb tension limit for spans over 200 ft.

†For 120-ft service drops, 450-lb limit.

Ampere loadings on distribution circuits often require that the temperature rise of the conductor due to resistance losses must also be taken into account.

18.19 JOINT-LINE CONSTRUCTION

Joint-line construction is used where two or more utilities would otherwise maintain separate pole lines, such as where both power and communication lines are routed along the same street.

Basis of Joint Use. Poles are used jointly under a *joint-ownership agreement* or under a *lease agreement*. Under joint ownership, the cost of providing the pole is borne jointly by the companies which share in its ownership. Division of expense is, in general, made in proportion to the space allotted to respective users. Clearance space, required between power and communication circuits and between the lowest attachment and ground, is disregarded in determining percentage of ownership. Clearance between higher-voltage and lower-voltage power circuits is chargeable to the higher-voltage circuits.

In case of leased space, the lessee acquires only the right to occupy a specified space. The owning company installs and maintains the pole and includes all charges in the rental price. Lessees usually install their own attachments and maintain them, though pin space is sometimes leased where space for only a few wires is required.

Construction Specifications. The types of construction, clearances, and relative levels of different classes of circuit should be provided for by a suitable specification, forming part of the agreement under which joint use is entered into. The general purpose is that construction of all parties be such as not to jeopardize the service or equipment of any of the other parties to the agreement. Construction requirements are set forth in the National Electrical Safety Code, ANSI C2. Some of the most important parts of such a specification are discussed in the following paragraphs.

Relative Levels of Supply and Communication Conductors. When supply and communication conductors are located on the same poles, it is generally desirable that the supply conductors be

located at the higher levels. This places the higher voltages near the pole top and the communication conductors at the lower levels. This relative location of facilities provides a lower probability of contact between the two systems since the supply conductors are usually larger than the communication lines. This also provides easier access to the lower-voltage or communication circuits by the line crews and avoids the need to climb through the supply conductors to work on the lower-voltage or communication systems. Where 600-V trolley feeders are carried on joint poles, the feeders are located for convenience at the approximate level of the trolley contact conductor.

Vertical Clearances. Spacing of conductor attachments must be appropriate with the requirements of safety in operation and maintenance. Clearance requirements are spelled out in detail in the National Electrical Safety Code, ANSI C2. Generally, a minimum vertical clearance of 40 in is used between communication conductors (or open wires of 0 to 750 V) and supply conductors operating between 750 and 8700 V to ground. Greater clearances are required for supply conductors operating above 8700 V. If the communication circuits belong to the utility for use in operating supply lines, reduced spacings of 16 and 40 in, respectively, are permitted.

Grades of Construction. Strength of poles must be such as to withstand ice and wind loadings normally experienced in the locality where the line is built, for all of the conductors to be carried. These conditions vary greatly in different parts of the United States, there being no ice in some parts of the country and a greater prevalence of wind in others.

Conductor Size. The size of conductors should be such that they do not experience a tension more than 60% of their rated breaking strength under conditions of maximum loading and not more than 25% of this value for final unloaded tensions at 60°F. Very little use is made in new construction of wire sizes smaller than No. 1/0 stranded aluminum or No. 2 ACSR.

Inductive Coordination. A vast majority of the newer telephone circuits on joint-use distribution lines are in cable, rather than open-wire, and telephone interference is rarely encountered. Where long exposures of open-wire circuits do exist, it may be necessary to make suitable transpositions in both power and communication circuits to eliminate electrical unbalances as much as practicable.

Aerial-Cable Construction. Insulated aerial cables carried by steel messenger cables have been used occasionally in primary distribution circuits where undergrounding is not practicable and special conditions, such as reduced clearances or unusually severe tree problems, exist. This type of cable is fastened to a galvanized-steel cable, or *messenger*, by means of brackets or lashings in a manner similar to large communication cables. Usually it consists of one, two, or three insulated conductors spiraled around the messenger which supports the assembly mechanically and usually serves as a neutral as well. This type of construction is finding very little usage in new system extensions.

Spacer-Cable Construction. Spacer-cable construction provides many of the advantages of aerial cable at lower cost. It consists of primary conductors having less insulation than the cable insulation which is customary for the circuit voltage, supported on a messenger and separated from each other by insulating spacers installed at suitable intervals along the line. Note, however, that the energized phase conductors of spacer cable are not directly cabled together with an effectively grounded neutral. They are held away from the neutral by a plastic spacer. Thus they meet Rule 230D of the National Electrical Safety Code, IEEE C2-1997, and must have the same clearances to other objects as bare conductors.

18.20 UNDERGROUND RESIDENTIAL DISTRIBUTION

During the past 40 years, the evolution of underground distribution systems, particularly single-phase systems to serve residential areas (URD), has proceeded at a rapid rate. For a so-called mature industry, the rate of change has been phenomenal. Costs have been steadily reduced through the introduction of new system concepts, improved installation practices, and the development of specialized equipment.

Nearly every utility in the United States now has a policy covering the installation of URD in new residential tracts. Conditions vary all the way from a substantial differential payment by the developer to a no-charge basis by the utility, although the developer usually is requested to assist with excavation. In addition, a number of states have established legal requirements mandating that all new residential developments in excess of a given number of homes be served by an underground distribution system. As a result, perhaps as many as two-thirds of new residential dwelling units are being served underground.

Cost. Underground distribution systems often cost more than comparable overhead systems. What are the principal factors contributing to the rapid growth of URD? These include

1. Greater public interest in the aesthetic appearance of residential communities.
2. Reduced cost of underground equipment and installations brought about by

Solid dielectric insulated cables—lower-cost—suitable for direct burial without duct systems

Factory-built cable terminations and splices of low cost easily prepared in the field by ordinary line crews without the aid of highly trained cable splicers

Mass production of specialized equipment such as pad-mounted transformers and accessories

Improved installation technique and equipment

Performance. Most observers are of the opinion that the frequency of faults is lower on underground systems than on overhead systems and that the faults are not so likely to “bunch up” because of storm conditions. However, faults are much more difficult and time-consuming to find, to isolate, and to repair on underground systems. This, coupled with the fact that many operating procedures cannot be performed on an underground system while it is energized and that it is impossible to make many of the temporary improvisations on underground circuits that can be accomplished on overhead systems, has led to the development of protective and sectionalizing equipment such as switches and separable cable connectors which often are physically integrated as accessory devices in the underground distribution transformers. In addition, several utilities with significant amounts of older cable have found that they are having more unexpected reliability problems as cables have aged.

Service-restoration requirements also have resulted in primary-system designs which operate as a normally open loop as shown in Fig. 18-41. In the case of a cable fault, this facilitates location and isolation of the failure and more rapid service restoration to all customers on the unfaulted portion of the primary loop. It is estimated that about 85% of primary URD systems are being operated as loops, the remainder being radial. Where radial laterals are used, many utilities provide portable, aboveground cables so that faulted cables can be bypassed temporarily and service restored while repairs are being made.

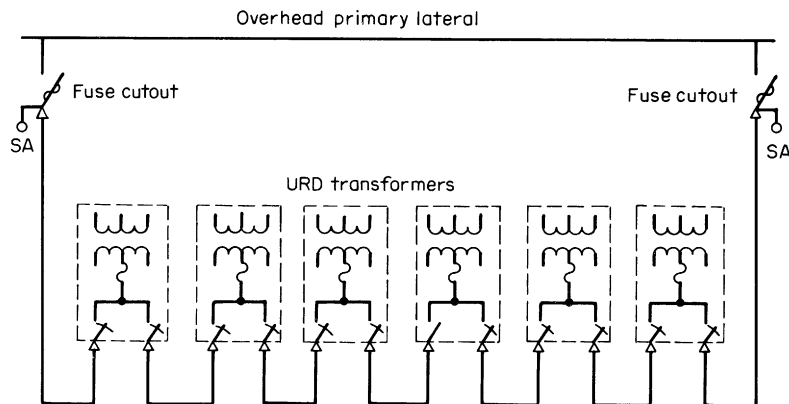
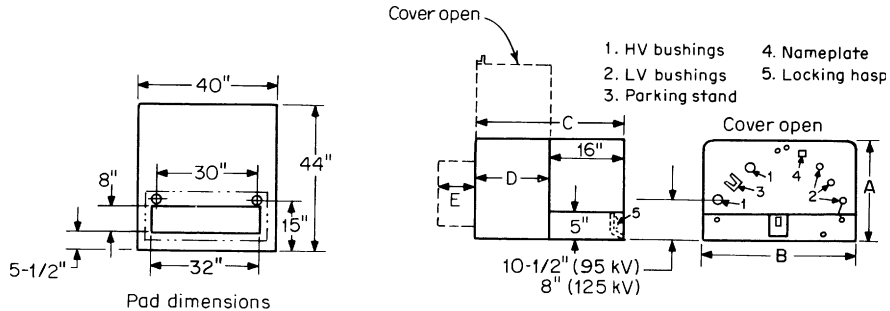


FIGURE 18-41 URD system derived from existing overhead circuits.



95- and 125-kV BIL (35 kV GrdY and below)

kVA	Dimensions, in				
	A	B	C	D	E
15	24	36	33.9	17.9	
25	24	36	33.9	17.9	
37.5	24	36	33.9	17.9	
50	24	36	33.9	17.9	8.0
75	24	36	40.0	24.0	8.0
100	26	36	40.0	24.0	8.0
167	32.5	36	40.0	24.0	8.0

FIGURE 18-42 Mini-pad distribution transformer. (*General Electric Company.*)

Transformers. The heart of the URD system is the single-phase distribution transformer because the primary cable terminations, switching and sectionalizing equipment, and overcurrent protective equipment usually are housed in the transformer enclosure. Thus most operating procedures require access to one or more distribution transformers. Three general types of single-phase transformers are in use.

Pad-Mounted. Figure 18-42 shows the predominant type of transformer being used for URD. The transformer shown is called the *mini-pad*. The term *pad* derives from the fact that transformers in this category usually are installed on concrete slabs, or pads.

The electrical functions of URD transformers cover essentially the same range as pole-type units. For reasons of safety, of course, they must be built in tamper-resistant configurations with no exposed electrically energized parts because of the proximity of such transformers to the general public.

The mini-pad in Fig. 18-42 has its cover open. The two primary bushings at the upper left are for use with load-break, separable insulated connectors, or elbows. This results in a “dead-front” configuration which is required to achieve the low-height mini-pad construction. The three 120/240-V bushings are at the right-hand side.

Many other combinations of pad-mounted construction and accessory equipment are available, including “live-front” primary connections with stress cones for the cables, internal or external primary fuses and switches, secondary circuit breakers, etc. Refer to appropriate product bulletins of the manufacturers or handbooks for further equipment details. Generally, the loadability of pad-mounted transformers is comparable with that of pole types.

Residential Subsurface Transformers (RST). Although usage of pad-mounted transformers predominates, a number of residential subsurface transformers are used. The RSTs are installed in relatively tight-fitting vaults with the cover grating of the vault at ground level.

Cooling is accomplished by natural convection of the air, although some users increase the efficiency of circulation by means of special chimneys to direct and control the circulation. With properly designed and installed chimneys, the loadability of RSTs is equal to that of pole types.

The RSTs must be submersible and therefore utilize dead-front primary cable terminations, usually the separable insulated connectors or “elbows.” Provisions for operation of accessories such as

switches, fuses, and circuit breakers are located on the cover of the transformer so that they can be operated by a member of the line crew standing on the surface of the ground. Usually the vault is too small for a person to enter.

Primary Cables. Primary URD cables are almost universally of the single-conductor concentric-neutral type employing polyethylene or cross-linked polyethylene insulation. Specifically, the use of TRXLPE and EPR are increasing in usage. Ordinary polyethylene is a thermoplastic which melts at temperatures in the order of 110°C. The process of “cross-linking” polyethylene converts it into a thermosetting material which does not have a melting point, per se.

Figure 18-43 shows a section of primary URD cable. The central conductor is the energized phase conductor, and the external concentric wires serve as the neutral.

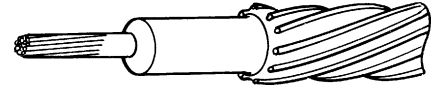


FIGURE 18-43 Concentric-neutral type of primary URD cable.

Corrosion of the copper concentric-neutral wires of primary URD cables results in reduced cross-sectional area of the wires, increasing their resistance. In some instances, the continuity of the wires is destroyed. Neutral corrosion may cause safety and operating problems on the URD circuit. Corrosion occurs when the neutral wires become anodic, which results in loss of metal. The wires may become anodic due to nearby dissimilar metals or to variations in soil characteristics along the cable route. Determining the location and extent of corrosion damage is a complex procedure which may involve surveys, testing, and in some cases, excavation. Corrective actions for existing cables include replacing portions of the cable, reestablishing the neutral circuit, and installing sacrificial anodes for cathodic protection. Corrosion in new installations can be controlled by the proper selection of materials, cable construction, type of installation, and cathodic protection. The use of jacketed concentric neutral cable to reduce the problem has been increasing over the years and was used by over 80% of respondents in *Transmission and Distribution's* 1990 survey on underground distribution practices. Most utilities directly bury the primary cables, although the trend to conduit is increasing. Often the URD cables are placed in the same trench as the telephone cables.

The precise calculation of voltage drop in direct-buried, concentric-neutral primary cables is quite complex because a portion of the single-phase load current flows in the concentric-neutral conductors and a portion in the earth surrounding the cable. Also, there may be an induced circulating current in the neutral conductors. Typical values of voltage drop per 100,000 A · ft are shown in Table 18-19.

TABLE 18-19 Single-Phase Voltage Drops per 100,000 A · Ft* for 15- and 35-kV Direct-Buried Concentric-Neutral Cables (Loop Values)

Conductor size	Voltage class									
	15 kV					35 kV				
	Lagging power factor									
	0.7	0.8	0.9	0.95	1.00	0.7	0.8	0.9	0.95	1.00
Underground primary										
Aluminum:										
Concentric-neutral—direct-buried, cross-linked polyethylene, conductor 70°C, neutral 60°C, earth resistivity 90 Ω-cm ³ , full insulation										
No. 2	44.1	46.6	48.1	48.1	44.8					
1/0	30.9	32.8	34.0	34.1	32.0	31.3	33.0	34.1	34.1	31.7
2/0	25.3	27.0	28.1	28.3	26.8	25.8	27.3	28.3	28.4	26.6
4/0	17.0	18.2	19.1	19.3	18.5	17.5	18.6	19.3	19.5	18.4

*Values in the table give the difference in absolute value between sending-end and receiving-end line-to-neutral voltages, in volts.

To use the table, calculate the ampere-feet as the product of the current in the phase conductor and the distance in feet between the source and the load. The effects of direct burial on impedance of the return current path are included in the tabulated voltage drops.

Secondary Cables. Usually three polyethylene-insulated, single-conductor cables are used for the 120/240-V secondaries and services. These may be separate cables or of triplex construction. In some cases a bare copper neutral conductor is used. The secondary and service cables are usually directly buried.

Cable Terminations. A major advantage of the polyethylene-insulated primary cable, in addition to low cost, is the ease with which it can be terminated in contrast with earlier traditional paper and lead cable, that is, cable insulated with oil-saturated paper with an outer lead sheath or jacket. Termination and splicing of a PILC cable requires a skilled cable splicer working with paper tapes and equipment for soldering and “wiping” the lead cover to potheads or to another section of PILC cable. Several hours are needed to prepare a 15-kV PILC cable termination.

The XLPE concentric-neutral cable can easily be prepared for termination by means of either a factory-made stress cone or a separable insulated connector. This preparation can be done by an ordinary lineworker in a hour or less using cutting jigs and tools to prepare the cable for the installation of the factory-made termination.

When the URD primary cable is terminated by means of a simple stress cone, the electrical connection to the terminal of the connected device usually is an exposed or “live-front” connection. When a separable insulated connection is used for termination, a “dead-front” construction is obtained; that is, all exposed surfaces of the cable and its termination are essentially at ground potential and thus present less of a hazard to operating personnel. In some cases, dead-front configuration allows a reduction in dimensions of the equipment.

Insulated connector modules are available in a great variety of configurations such as the elbow and bushing, multitaps, stand-off bushings for temporary use on parking stands, load-break modules, and T taps. Figure 18-44 illustrates a cutaway view of a switch (load-break) module, and Fig. 18-45 is a similar illustration of an elbow connector and module.

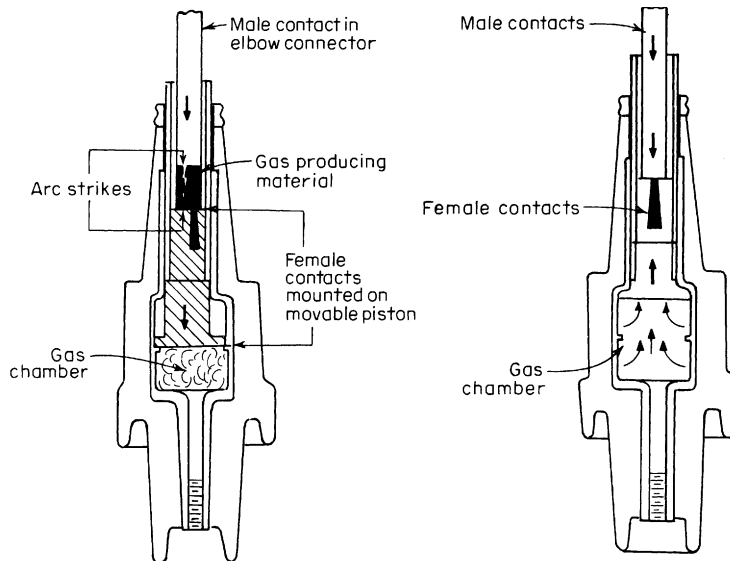


FIGURE 18-44 Piston-action 25-kV connector. (General Electric Company.)

The basic separable connector system used with URD distribution transformers usually is rated 200 A continuous and is available to either load-break or non-load-break form. See appropriate product bulletins or handbooks of the manufacturers for further product description.

System Types. About 65% of URD systems are installed along the streets in front of the houses, or “front-lot.” The remaining 35% are “rear-lot” systems. There are obvious operating and maintenance problems associated with access to the rear-lot location. At the moment there does not appear to be any strong trend toward either option.

An extremely large number of combinations of transformer equipment are being used, and a detailed discussion of them is beyond the scope of this handbook. However, the following listing is reasonably representative of “typical” practice:

1. Pad-mounted transformer of the mini-pad configuration
2. Primary laterals operated as normally open loops
3. 12.47 grounded Y/7.2-kV primary voltage
4. The primary lateral loops through each distribution transformer, that is, there are two primary cable connections to each transformer (see Fig. 18-41)
5. Front-lot construction
6. Four to eight homes served by each transformer
7. Transformers of dead-front construction load-breaking separable insulated connectors
8. Internal fusing for each transformer
9. Direct-buried, cross-linked polyethylene insulated cables

Homes Served per Transformer. There is an optimal number of homes to serve from each transformer depending on the load per home, size of lots, and type of system to be used. For a given load per home and lot size, the cost per kVA of transformer decreases as the number of homes increases. This is so because increasingly larger transformers would be used.

However, as the number of homes per transformer increases, the cost of the secondary and service system increases because of the larger secondary cable required. Since the total cost is the sum of those costs, an optimum number of homes per transformer will exist.

In making such an economic study, it is necessary to examine the secondary-service-system voltage drop. A detailed study also should evaluate transformer and cable losses for the various arrangements.

Four to eight homes served per transformer seems to be reasonably typical of present practice. Larger loads per home and larger lot sizes favor a smaller number of homes per transformer. Conversely, smaller loads per home and smaller lot sizes favor serving more homes from each transformer.

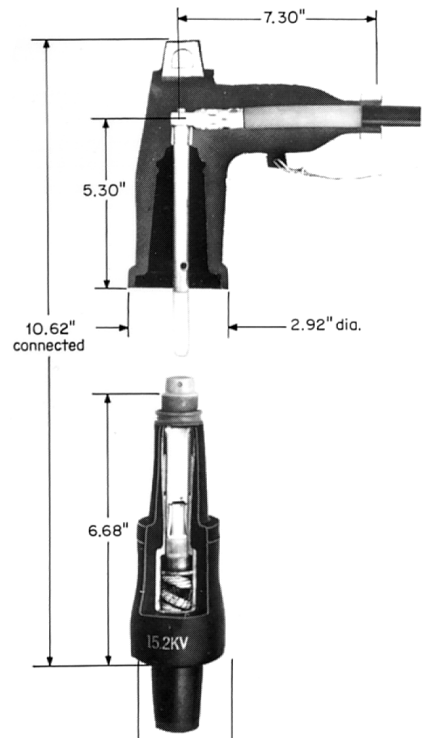


FIGURE 18-45 Cutaway view of elbow connector and switch module. (General Electric Company.)

18.21 UNDERGROUND SERVICE TO LARGE COMMERCIAL LOADS

Large commercial loads constitute one of the major segments of utility distribution systems, especially in built-up areas where underground supply systems are a requirement. Demands range from a few hundred to many thousands of kVA per customer, and the engineering and design time to

provide adequate service facilities is substantial. Each job is special, requiring selection of appropriate and correctly sized equipment, negotiation of space and layout with building owners or their consultants, and frequently a detailed discussion of facilities, charges, rates, and contracts. The best tool the distribution engineer has is an adequate knowledge of the systems and components which are available, together with guidelines on their cost and reliability. Beyond this, engineering common sense and reasonable operating practices must be combined with the other factors in order to arrive at a decision on the method of service.

Characteristics of Large Commercial Loads. All large commercial loads generally involve the following factors:

1. *Loads* are in the range of 300 to 4000 kVA or more. The larger loads (even up to values of 50 or 75 MVA) are normally supplied by multiples of lower-capacity services.
2. *Utilization voltage* is 480Y/277, although smaller loads may be 208Y/120 and some of the larger institutional loads may be 4160Y/2400 (with the customer providing further step-down).
3. Individual *service size* is limited to about 4000 A by availability of service entrance switching, maximum fuse or breaker sizes, largest commercial wiring systems, and a growing “gut feeling” that this represents enough eggs in any one basket. Providing adequate interrupting capacity is also a definite factor, and single transformers above 4000 A may be priced as specials.
4. *Installation space* is limited and has a high value to the owner. Utility equipment must be as compact as possible and should not require exceptional customer requirements for auxiliaries.
5. Each job is one-of-a-kind and requires much *custom engineering* as well as detailed coordination with the owner of the building facilities. Complex commercial considerations are also involved, covering rates, ownership of facilities, contracts, and future maintenance responsibilities.
6. Service quality must be high, as to both voltage regulation and continuity. Frequent interruptions are not tolerable, and long planned interruptions are not feasible. Service complaints when expressed are long and loud.

Service Arrangements. Several basic service arrangements can be considered for these loads:

1. Radial
2. Primary loop
3. Primary selective
4. Secondary selective
5. Spot network

If radial service were adequate, there would be no need for the succeeding systems because the radial system is the least complex and the least expensive. Unfortunately, when the supply system is underground, it also is the least reliable and generally is unsatisfactory except in special cases. The principal drawback of the radial system is its exposure to long interruptions due to component failure and the necessity for repeated planned interruptions for routine maintenance or new construction.

These five basic service systems are illustrated in Fig. 18-46, which also shows a basic main feeder system of two similar underground feeders.

Radial System. The radial system is exposed to many interruption possibilities, the most important of which are those due to primary cable failure or transformer failure. Either event will be accompanied by a long interruption, reported nominally by utilities as 10 to 12 h. Both components have finite failure rates, and such interruptions are expected and statistically predictable. The system will be satisfactory *only* if the interruption frequency is very low and if there are ways to operate the system without planned outages.

Primary Loop. A great improvement is obtained by arranging a primary loop, which provides two-way feed at each transformer. In this manner, any section of the primary can be isolated, without

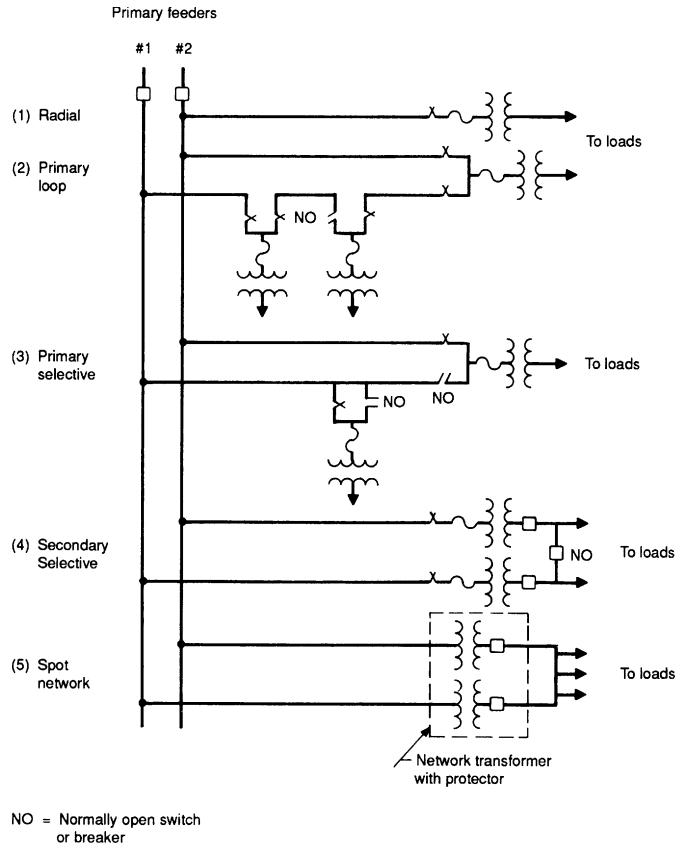


FIGURE 18-46 Five basic service systems.

interruption, and primary faults are reduced in duration to the time required to locate a fault and do the necessary switching to restore service. The cable in each half of the loop must have capacity enough to carry all the load. The additional cable exposure will tend to increase the frequency of faults, but not necessarily the faults per customer. The addition of a loop tie switch at the open point also introduces the possibility of a single equipment fault causing an interruption to both halves of the loop. Murphy's law generally applies to these situations. Automatic loop switching to reduce interruption duration further is very difficult to arrange and is not normally applied to these systems.

Primary Selective. This system uses the same basic components as in the primary loop but arranged in a dual or main/alternate scheme. Each transformer can "select" its source, and automatic switching is frequently used. When automatic, the interruption duration can be limited to 2 to 3 s. Each service represents a potential two-feeder outage (if the open switch fails), but under normal contingencies, service restoration is rapid and there is no need to locate the fault (as with the loop) prior to doing the switching. This scheme is in popular use on many underground systems. Switching times can be improved to less than $\frac{1}{2}$ cycle with the use of a static transfer switch (STS).

Secondary Selective. This service system uses two transformers and low-voltage switching. It is not in popular use by utilities for 480-V service but is common in industrial plants and on institutional properties. Primary operational switching is eliminated and with it some causes of difficulty. Duplicate transformers virtually eliminate the possibility of a long interruption due to failure. Load is divided between the two units, and automatic transfer is employed on loss of voltage to either load.

There must be close coordination of utility and customer during planned transfers, and the split responsibility is probably the principal reason for its limited use as a service system.

Secondary Spot Network. Maximum service reliability and operating flexibility are gained by a spot network using two or more transformer/protector units in parallel. The low-voltage bus is continuously energized by all units, and automatic disconnection of any unit is obtained by sensitive reverse power relays in the protector. Maintenance switching of primary feeders can be done without customer interruption or involvement. Spot networks are common in downtown, high-density areas and have been applied frequently in outlying areas for large commercial services where the supply feeders can be made available. This system also represents the most compact and reliable arrangement of components for service in underground systems.

18.22 LOW-VOLTAGE SECONDARY-NETWORK SYSTEMS

Distributed or grid-type secondary network systems have been used for many years by electric utility companies to serve high-density load areas in the downtown section of cities. Secondary networks are used in about 90% of the cities in this country having a population of 100,000 or more and in more than one-third of all cities with population between 25,000 and 100,000.

The service voltage is 208Y/120 V supplying light and power loads in stores, hotels, restaurants, office buildings, apartment houses, and in some cases individual residences. The systems and equipment are entirely underground, and the 208Y/120-V portion consists of grids of interconnected cables supplied at numerous points by network transformers which feed the grid through network protectors.

A given secondary network is supplied by several primary feeders suitably interlaced through the area in order to achieve acceptable loading of the transformers under emergency conditions and to provide a system of extremely high service reliability. Primary voltages are found in the range of 5 to 34.5 kV, with the 15-kV class predominating. See Fig. 18-47.

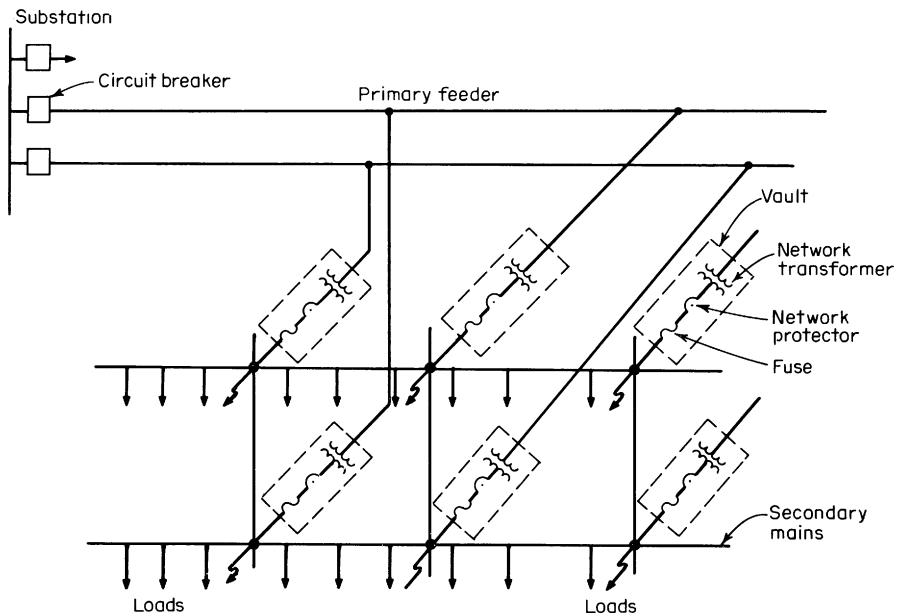


FIGURE 18-47 Schematic diagram of small segment of a secondary network.

The number and routing of the primary feeders are usually based on the assumption that the loss of one or two feeders will not cause a service interruption. For example, the design bogey may be such that the network can operate satisfactorily during the forced outage of one feeder when another feeder is out of service for repairs or maintenance (single contingency).

The secondary cable system is designed so that the loss of one transformer will not cause low voltage or a service interruption. Secondary cable faults in 208Y/120-V networks are allowed to burn clear or are cleared by means of limiters, which essentially are fuses having characteristics proportioned to protect the cable and to coordinate with other protective devices. Secondary faults usually will *not* burn clear on 480Y/277-V networks, so limiters are used extensively in these systems. Usually the secondary mains consist of two or more cables in parallel so that failure of one cable does not result in a service interruption.

Network Transformers. The network protector is mounted on one end of a network transformer, and the primary disconnecting and grounding switch is usually on the other end. In some installations the network protector is isolated from the network transformer, with the connection between the low-voltage terminals of the transformer and the protector made with insulated low-voltage cables. The typical network transformer is 3-phase, 216Y/125 V, oil-cooled, in a heavy corrosion-resistant tank suitable for installation in subsurface vaults under streets or sidewalks. Occasionally, there are installations in dry locations where submersible construction is not required. Five hundred kVA is a very common rating, although 750- and 1000-kVA units are available and in use. (For *spot* networks of 480 Grd Y/277 V, transformer ratings are available through 2500 kVA.) There are only two or three distributed street networks at 480Y/277 V in the United States.

Network Protectors. The network transformer is connected to the secondary network through a network protector (NWP) as shown in Fig. 18-47. The NWP is an air circuit breaker with relays and auxiliary devices and backup fuses, all enclosed in a metal case, which usually is physically mounted on the secondary side of the transformer. The functions of the relays are

1. To open the NWP on power-flow reversal, or in case of a fault in the transformer or in the primary feeder
2. To reclose the NWP when the voltage of the primary feeder is of the correct magnitude and phase relation with respect to the network voltage so that when the NWP closes, power (watts) and vars will flow *from* the feeder *into* the network

Thus, if there is a fault on a primary feeder, it is cleared by operation of the feeder breaker at the substation and the opening of all network protectors on transformers supplied by that feeder. Also, if a feeder breaker is opened manually in preparation for maintenance work on the feeder, all NWPs on that feeder should open automatically because of the reverse power flow caused by excitation of the transformers from the low-voltage side.

Cables. All primary and secondary cables are routed along the streets in duct lines as indicated in Fig. 18-47. Loads are served along the streets and at intersections as shown. Primary cables traditionally have been paper-insulated, lead-covered (PILC), but the solid-dielectric insulated cables have gained rapid acceptance. Secondary cables have commonly used rubber insulating materials, but polyethylene and ethylene propylene rubber insulations now are used extensively. Manholes at street intersections are large enough to hold numerous cable connections and limiters and to allow workers to pull and splice cables.

Continuity of Service. Continuity of service is the outstanding advantage of a network system. When a failure occurs in a primary feeder or in a transformer, the faulty feeder is automatically disconnected, and service continues without interruption. Secondary cable faults are allowed to burn clear or are cleared by means of limiters without loss of service. Substations supplying networks are

so designed that typical substation faults will not shut down the network; this is further enhanced by careful interlacing of the primary feeders through the load area and their connection to different bus sections in the substation. It is strongly recommended that a given secondary network be supplied from only one substation. If a network is supplied, for instance, from two different substations, it is possible under some system conditions for power to flow from one substation to the other through the secondary grid and network transformers. Should this occur, some network protectors could “see” reverse power flow and open, thus resulting in the undesirable disconnection of these transformers from the network.

Network Size. A secondary network supplied by five or more feeders will keep transformer loadings at 125% or less during the outage of one primary feeder. If the feeders are in the 15-kV class, each feeder could easily supply six 1000-kVA or twelve 500-kVA network units. Thus five feeders interlaced could supply a 30,000-kVA network under idealized conditions. With 500-ft-square blocks, 1000 kVA per block corresponds to 112 MVA of load per square mile. Some utilities plan for the emergency outage of one feeder while a second is out of service for maintenance.

In general, 208Y/120-V networks are in the order of 30,000 to 40,000 kVA in size. There are many networks smaller than this range and some larger. One important limitation to the size of a secondary network is the ability to restore service after the network has been shut down.

Spot Networks. New commercial buildings in existing 208Y/120-V network areas usually have very large electric loads. These loads frequently are supplied by 480Y/277-V *spot* networks, since it is impractical to handle individual loads much larger than about 200 kVA from the 208Y/120-V street networks, and 480Y/277 V is an excellent voltage for supplying large commercial buildings. In some cases the spot networks are supplied from primary feeders which also serve a distributed network. Early 480Y/277-V spot networks used the same overcurrent protective devices employed successfully for clearing faults in the 208Y/120-V networks. Included are the network relays in the protector for detecting faults on the primary feeders, and the network protector fuses, cable limiters, and service fuses for detecting and isolating faults in the secondary systems. Some 208Y/120-V systems do not use cable limiters, as faults in the 208Y/120-volt network systems are self-clearing under some circumstances.

Operating experience with the 480Y/277-V spot network systems showed that some faults were arcing in nature, drawing significantly less current than that available for a bolted fault. Many of these faults would not self-clear or would self-clear only after extensive damage was done at and around the original point of fault. Also, some of these faults did not draw sufficient current to blow fuses, or else blew fuses only after significant damage was done at the point of fault.

As a result, some utilities have installed devices for detecting and clearing low-current arcing faults in the 480-V portions of the spot-network system. Heat sensors and ground-fault relays are the most commonly installed devices for the detection function. Clearing has been accomplished by tripping of the network protector, which is effective only for faults downstream from the protector terminals. In a few instances, vacuum circuit breakers or interrupters have been installed on the high-voltage side of the network transformer to clear faults in the associated network transformer, network protector, and other portions of the 480-V system.

Network Monitoring. Remote monitoring capability has been added to a few in-service secondary network systems to automatically gather data needed for the operation and planning of the system. Heretofore, such data were obtained from manual measurements at vaults and manholes. With remote monitoring, the data are continuously collected and transmitted to an operations center or other location for manual and computer analysis. Telephone lines, power-line carrier, two-way radio, and fiberoptic cable have been used as the communications links from the network vaults and other monitored sites of the substation or elsewhere. Virtually any quantity which can be digitized can be monitored. Examples of monitored quantities are the load on the protectors, protector position (open or closed), network protector fuses status (okay or blown), network transformer temperature, vault temperature, bus voltage, and vault water level. In several monitoring systems with two-way communications, it is possible to remotely trip or close the network protectors.

High-Rise Buildings. Primary-voltage feeders are being used as the riser feeder in high-rise buildings. A rule of thumb is that if an apartment building is 10 floors or more, it is more economical from an overall point of view to use the primary voltage rather than utilization voltage for the riser feeder. Similarly, for a commercial building with 480Y/277-V utilization, a building of 50 floors or more usually justifies the use of primary voltage feeders as risers in the building.

The primary system pattern within a high-rise building is usually a loop as shown in Fig. 18-48 or multiple as shown in Fig. 18-49. This will allow cable faults to be manually isolated by proper switching so that cable faults will cause only short interruptions to customers. Customers fed radially through a transformer will be without service if the transformer fails until a temporary connection can be made to an adjacent transformer. For more important loads like elevators, hall lighting, and fire pumps, better reliability is often obtained by using a spot network or low-voltage selective system.

Dry-type transformers using air as the insulating medium of the transformers are the most desired for high-rise buildings. This is so because no special provisions have to be made in the transformer room, such as fireproofing for oil-filled or venting the transformer to the outside of the building for nonflammable liquid-filled transformers. Many of the transformer rooms for apartment buildings and some commercial buildings are in the core of the building, which makes it difficult to use the liquid-filled transformer. However, transformers for supplying heavy loads, such as air conditioning in commercial buildings, usually can be located against an outside wall on machinery floors of the building. This makes it relatively easy to vent a nonflammable liquid-filled transformer to the outside of the building. Hence network transformers are often used for this application.

The primary load-break switch or load-break connector with a fuse can be arranged for either the multiple or loop type of feed where the short-circuit current available is within their rating. Usually the primary short-circuit current available is in the 8000- to 10,000-A range. The current-limiting type of fuse is often used for this "inside-the-building" application because it does not discharge ionized gases or noise during interruption.

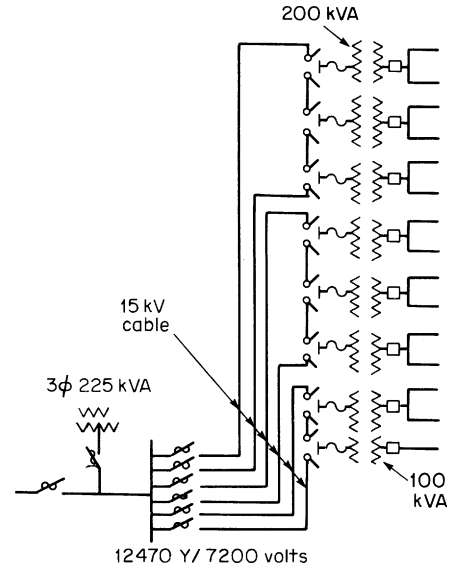


FIGURE 18-48 Schematic diagram of a looped primary system.

18.23 CONSTRUCTION OF UNDERGROUND SYSTEMS FOR DOWNTOWN AREAS

Underground construction is required in the built-up downtown areas of cities where the distribution system serves a multiplicity of concentrated commercial loads. Usually the distribution circuits are installed in conduits or duct lines along the city streets. Equipment such as switches and transformers is installed in vaults under the streets or sidewalk or in rooms located within the buildings.

Inflexible conduit systems have not been used widely in the United States except for the early Edison systems and are now completely obsolete. In this system, the conductors were insulated copper rods which were placed in an iron pipe which was then filled with a melted asphaltic compound which solidified on cooling. The tube sections were laid in a trench, joined together, and directly buried. For many years, inflexible conduit systems also were used in Europe; however, in the United States flexible systems gained preference because of the expense and inconvenience of digging through street surfaces in order to make repairs or replacements.

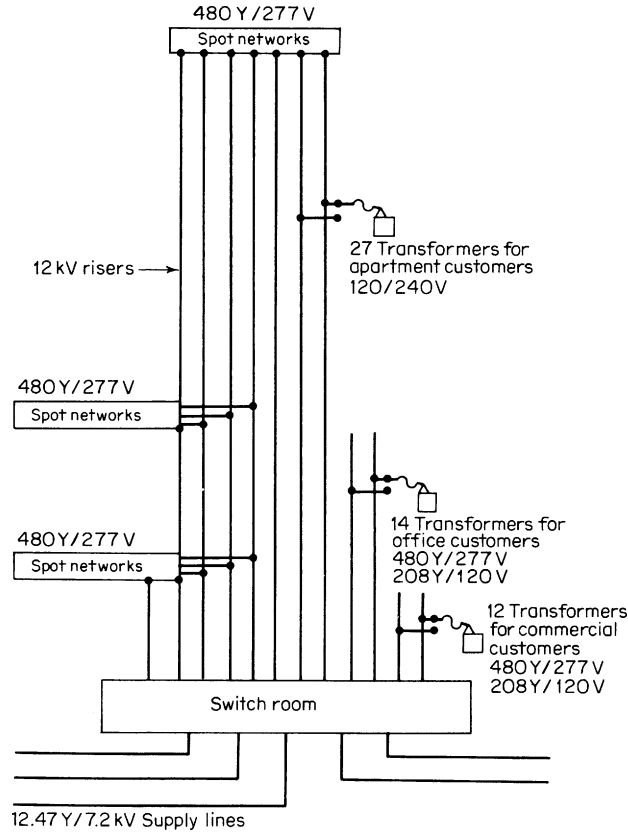


FIGURE 18-49 One-line diagram of the multiple primary system for John Hancock Center.

The flexible underground system consists of ducts or pipes extending between manholes. This type of system has the advantage of minimum disturbance of street pavement and interference with traffic. Cables can be drawn or withdrawn from manhole locations for repairs or changes. Manholes are placed at all junction points, corners, and as needed for secondary and service cables. The spacing of manholes depends on the types of circuits installed, varying considerably between through-type and local distribution circuits. In straight runs, the intervals may be as great as 500 to 700 ft, depending on the allowable cable-pulling tensions and utility practice.

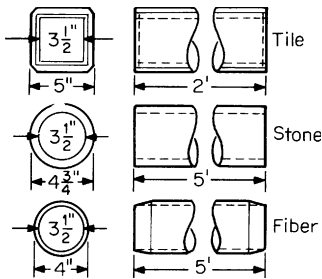


FIGURE 18-50 Types of single duct for underground conduits.

Duct Materials and Practices. Many types of suitable materials have been used for cable ducts, such as fiber-clay tile, concrete, plastic, fiberglass, and soapstone. Preference varies from one utility to another. In general the material should be impervious to water and not degraded by chemical action or electrolysis. The bore usually is round and should be smooth to avoid damage to the cable sheath or jacket. The diameter of the bore should be adequate to accept the largest-diameter cable envisioned for the foreseeable future. Several types of single duct are shown in Fig. 18-50. Diameters ranging from 3 1/2 to 6 in are common.

For underground distribution systems, a duct line usually is built up of a number of single ducts, often arranged in a rectangular array and encased in concrete as shown in Fig. 18-51. For secondary-network systems, duct lines containing 6 to 12 ducts are frequently used.

Number of Ducts. The number of ducts in a given duct line should be sufficient to accommodate anticipated load growth for a number of years in the future. Theoretically, the most economic form of duct structure would be two ducts wide. However, when more than six or eight ducts are required, this design may lead to excessive depth. As a result, usually a rectangular construction, three or four ducts wide and three or four ducts deep, is used, as shown in Fig. 18-51. The maximum number of ducts to be put into a duct line is governed chiefly by thermal limitations. It is desirable to have as many ducts as possible on the outside of the bank in order to facilitate heat transfer to the surrounding earth. Insofar as possible, the inner ducts should be used for cables which produce little heat. Since space for training cables in manholes is limited, it becomes more difficult to rack and train cables when the incoming duct line is several ducts wide and several ducts deep.

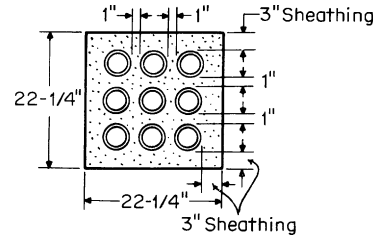


FIGURE 18-51 Arrangement of conduit with concrete sheath.

Location of Manholes. Manholes provide protected and accessible space in which cables and associated equipment can be operated efficiently. They must be provided in sufficient number to permit pulling in cable without excessive tension, to house necessary transformers and switching equipment, and to provide for splices and service connections.

On long runs the manhole spacing usually is not more than 500 or 600 ft. Where local distribution circuits are involved with numerous service connections, manholes may be located about 100 ft apart. Manholes or vaults to house transformers must be large enough to provide working room and proper ventilation. Location of transformer vaults in the sidewalk area is preferred, and sidewalk gratings are commonly provided to improve ventilation. For locations in the street or in areas accessible to vehicular traffic, the vault roof and gratings must be designed to withstand anticipated loadings.

Many sizes and shapes of manholes are used. The design used for a particular installation may well be governed by the presence of local obstructions such as gas lines, water pipes, or conduit lines of other utilities. For cable manholes in the streets, many utilities have standardized on a rectangular or coffin-shaped design with the long axis parallel to the duct line. The manhole should be deep enough to allow the lowest duct to enter about a foot above the floor and should have 5 to 6 ft of clear headroom for workers. Also, the bottom of the manhole should be higher than the adjacent sewer system so that a drain can be effective in keeping it dry. Figures 18-52 and 18-53 illustrate two types of cable manholes.

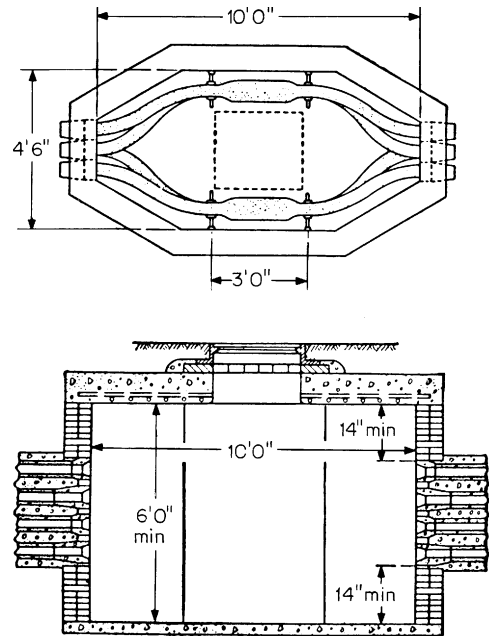
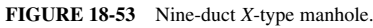
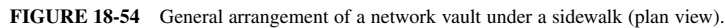


FIGURE 18-52 Straight-type manhole.



The most prevalent types of transformer vaults are found in secondary network systems. They may be located under sidewalks or streets or partly or entirely within buildings. The arrangement, size, and shape of a network vault are determined by the number and rating of network transformers to be installed and the nature of accessory equipment, such as primary switches. Figure 18-54 shows the general arrangement of a sidewalk vault arranged for two network units with network protectors and primary switches. The roof consists of removable slabs of sidewalk concrete (not shown), and access is available at either end by iron steps. Under normal conditions, the entrances are covered with suitable metal gratings or grills which allow for circulation of air.

The exact final depth of the ditch often cannot be determined until the depths of pipes and conduits crossing it have been disclosed by excavation. Alignment and grades should be



18.24 UNDERGROUND CABLES

For most distribution circuits in the 5-kV class or higher, the cables employ a shielded construction. *Shielding* is the use of a conducting or semiconducting material on the surface of insulating material to confine the electric field to the insulation proper and to avoid undesired concentrations of electric stress. Shielding is used on the outer surface of the cable insulation or directly over the main conductor, or both. Outside shielding, often in the form of metallic tapes, metallic sheaths, or

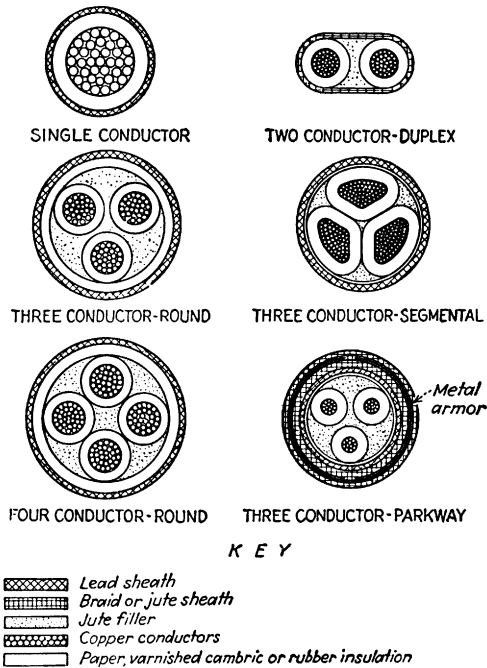


FIGURE 18-55 Cross sections of typical cables.

concentric wires, must be effectively grounded. This shielding also provides a return path for short-circuit current in the event of cable failure and protects workers from the shock of charging current.

Number of Conductors. Cables can be classified as single-conductor, 2-conductor, 3-conductor, etc., according to the number of separately insulated conductors enclosed by a single sheath or jacket (Fig. 18-55).

Cable Insulation. Electric supply cables are insulated with a wide variety of insulating materials depending on voltage ratings, type of service, installation conditions, etc. In the past, the following have been commonly used:

1. Rubber and rubberlike for 0 to 35 kV
2. Varnished cambric for 0 to 28 kV
3. Impregnated paper of the solid type for voltages up to 69 kV and with pressurized gas or oil up to 345 kV or higher

These insulation systems usually require a sheath or suitable jacket to prevent infiltration of moisture, loss of oil, gas, or impregnant,

and to provide protection against corrosion and electrolysis. In some cases, an armor overlay is used to provide mechanical protection. With impregnated-paper insulation of the solid type, a lead sheath is usually provided.

A wide variety of joints, splices, and terminations is used, depending on the voltage, cable insulation, number of conductors, jacketing or sheathing material, and method of shielding. Joints, splices, and terminations are discussed in more detail later in this section.

Single-conductor cables are used, of course, in single-phase primary system for residential service and normally are used in single-phase or 3-phase secondary systems where many taps and connections are involved. Single-conductor cables also are frequently used in direct-buried, 3-phase primary systems. Three-conductor primary cables are often used in duct systems where they have the advantage of occupying only one duct. Several typical cables are shown in Fig. 18-55.

At the present time, solid-dielectric insulating materials such as tree retardant, cross-linked polyethylene, and EPR are receiving the widest application in underground distribution systems, both direct-buried and duct systems. Principal reasons for the wide usage of these insulations are

1. Low cost.
2. Suitability for direct burial or for use in duct systems.
3. Sheath or jacket not generally required.
4. Much easier to tap, splice, and terminate than systems such as solid impregnated paper. Factory-made splices, connectors, and terminations are available and widely used.
5. Excellent mechanical and electrical properties.

In a 2004 survey on procurement practices relating to underground distribution cable covering 60 investor-owned utilities and representing 70% of the total investor-owned utility customers, Dudas and Fletcher reported the following trends:

TABLE 18-20 Insulation Thickness for Cross-Linked, Thermosetting, Polyethylene-Insulated Cable

Rated circuit voltage, phase-to-phase volts	Conductor size, AWG or kcmil	Insulation thickness for 100% and 133% insulation levels	
		mils	mm
0–600	14–9	45	1.14
	18–2	60	1.52
	1–4/0	80	2.03
	225–500	95	2.41
	525–1,000	110	2.79
601–2,000	4–9	60	1.52
	8–2	70	1.78
	1–4/0	90	2.29
	225–500	105	2.67
	525–1,000	120	3.05
2,001–5,000	8–1,000	90	2.29
5,001–8,000	6–1,000	115	2.92
8,001–15,000	2–1,000	175	4.45
15,001–25,000	1–1,000	260	6.60
25,001–28,000	1–1,000	280	7.11
28,001–35,000	1/0–1,000	345	8.76

Note: 100% level applied where system overcurrent protection is such that ground faults are cleared within 1 min. Applies to the great majority of distribution systems. 133% level applied where clearing time of 100% level cannot be met, but there is assurance of fault clearing within 1 h. Minimum-size conductors should be in accordance with above values to limit maximum voltage stress on the insulation at the conductor to a safe value.

Source: Adapted from IPCEA Pub. S-66-524, NEMA Pub. WC-7-1471. Revision No. 3, September 1974.

- The survey indicated a significant preference for tree retardant crosslinked polyethylene (TRXLPE) over EPR cable.
- The majority specified concentric neutral on 200 A cable and LC shield, flat strap, flat wire or tape shield on 600 A cable.
- 78% specified an encapsulating jacket rather than an overlaying jacket.
- 95% of the utilities specified an insulating polyethylene compound for their cable jackets.

Insulation thickness for typical cross-linked, polyethylene-insulated, nonjacketed distribution cables are given in Table 18-20. Thickness for most ratings of non-cross-linked polyethylene cables are essentially the same.

Cable Diameters. Overall diameter D of a cable may be computed from the diameter of its conductors d , the thickness of its conductor insulation T , its belt insulation t , and its lead sheath S , as follows:

$$\text{Single-conductor:} \quad D = d + 2T + 2S \quad (18-22)$$

$$\text{2-conductor:} \quad D = 2(d + 2T + t + S) \quad (18-23)$$

$$\text{3-conductor:} \quad D = 2.155(d + 2T) + 2(t + S) \quad (18-24)$$

$$\text{4-conductor:} \quad D = 2.414(d + 2T) + 2(t + S) \quad (18-25)$$

These formulas apply to conductors of circular cross section. For sector-type 3-conductor cables, the overall diameter

$$D_3 = D - 0.35d \quad \text{approx.} \quad (18-26)$$

Electrical Characteristics of Cable. Skin effect is an ac phenomenon whereby alternating current tends to flow more densely near the outer surface of a conductor than near the center. That is, the magnetic-flux linkages of current near the center of the conductor are relatively greater than the linkages of current flowing near the surface of the conductor. The net effect is that the effective resistance of the cable is greater for alternating current than for direct current. This effect increases as the conductor size increases and as the frequency increases. It is also a function of the relative resistance of the conductor material, being less for materials of higher resistance; for example, the skin effect for a given diameter of cable is great if the material is copper rather than aluminum. Because of skin effect, large cables are sometimes built up over a central core of nonconducting material.

The nonuniform distribution of alternating current across the cross section of the cable also has the effect of reducing the effective internal inductance of the cable. Usually, this effect is extremely small in distribution circuits and is neglected.

It should be noted that magnetic flux linking the cable because of nearby current also can affect the cross-sectional distribution of current and can significantly change the effective ac resistance of the cable for multiconductor cables or cables in the same duct. This is known as the *proximity effect*. Most tables of conductor characteristics list factors which combine the results of the skin effect and proximity effect.

If an insulated cable has an outer metallic wrapping such as sheaths, metal pipes, or concentric-neutral conductors installed in such a manner that induced circulating currents can flow normally in these external conductors, losses will occur in these circuits, reducing the ampacity of the cable.

Skin-Effect Coefficients. Skin-effect and proximity-effect coefficients are given in Table 18-20 for copper and aluminum conductors at 25°C. To determine the skin effect on the effective resistance of

TABLE 18-21 DC Resistance and Correction Factors for AC Resistance

Conductor size, AWG or kcmil	DC resistance, $\Omega/1000$ ft at 25°C*		AC resistance multiplier			
			Single-conductor cables†		Multiconductor cables‡	
	Copper	Aluminum	Copper	Aluminum	Copper	Aluminum
8	0.6532	1.071	1.000	1.000	1.00	1.00
6	0.4110	0.6741	1.000	1.000	1.00	1.00
4	0.2584	0.4239	1.000	1.000	1.00	1.00
2	0.1626	0.2666	1.000	1.000	1.01	1.00
1	0.1289	0.2114	1.000	1.000	1.01	1.00
1/0	0.1022	0.1676	1.000	1.000	1.02	1.00
2/0	0.08105	0.1329	1.000	1.001	1.03	1.00
3/0	0.06429	0.1054	1.000	1.001	1.04	1.01
4/0	0.05098	0.08361	1.000	1.001	1.05	1.01
250	0.04315	0.07077	1.005	1.002	1.06	1.02
300	0.03595	0.05897	1.006	1.003	1.07	1.02
350	0.03082	0.05055	1.009	1.004	1.08	1.03
500	0.02157	0.03538	1.018	1.007	1.13	1.06
750	0.01438	0.02359	1.039	1.015	1.21	1.12
1000	0.01079	0.01796	1.067	1.026	1.30	1.19
1500	0.00719	0.01179	1.142	1.058	1.53	1.36
2000	0.00539	0.00885	1.233	1.100	1.82	1.56

Note: 1 ft = 0.3048 m.

*To correct to other temperatures, use the following:

For copper: $R_T = R_{25} [(234.5 + T)/259.5]$

For aluminum: $R_T = R_{25} [(228 + T)/253]$ where R_T is the new resistance at temperature $T(^{\circ}\text{F})$ and R_{25} is the tabulated resistance.

†Includes only skin effect (use for cables in separate ducts).

‡Includes skin effect and proximity effect (use for triplex, multiconductor, or cables in the same duct).

a single-conductor 1000-kcmil copper cable operating at 25°C, refer to Table 18-21, where the dc resistance is 0.01079 Ω /1000 ft and the skin-effect coefficient is 1.067. The effective resistance at 60 Hz is $1.067 \times 0.01079 = 0.0115 \Omega$ /1000 ft, 6.7% greater than for direct current. For a similar 2000-kcmil, the increase in resistance for alternating current is 23.3%; the ampacity of the cable is reduced to $100/1.233 = 81.1\%$.

The last two columns of Table 18-21 give the coefficients for multiconductor cables or cables in the same duct. They are used in the same manner as in the previous examples. For the larger conductors, the derating factor is substantial.

Electrostatic Capacitance. The capacitance of a shielded or concentric-neutral single-conductor cable is

$$C = \frac{0.00736K}{10^6 \log_1(D/d)} \quad (18-27)$$

where C = capacitance, farads/1000 ft
 K = dielectric constant of insulation
 D = diameter over the insulation
 d = diameter over the conductor shield

Charging Current. The charging current of a single-conductor cable is

$$I = \frac{0.0463EfK}{1000 \log_1(D/d)} \quad (18-28)$$

where E = voltage to neutral, kV
 f = frequency, Hz
 I = amperes per 1000 ft, charging current

For overhead circuits at distribution voltages and power frequencies, the charging current usually is negligible. It may become significant in high-voltage transmission circuits, as discussed in Sec. 14. For insulated cables, the charging current is relatively greater than in overhead circuits because of close spacing and the higher dielectric constant of the cable insulation; $K = 1$ for air and 3.3 for impregnated paper. For unfilled polyethylene $K = 2.3$, and it may run as high as 2.9 for filled, cross-linked polyethylene.

Geometric Factors. Charging current of 3-phase three-core cable is affected by arrangement of conductors (round or sector) and by relative thicknesses of conductor insulation T and belt insulation t . These relations have been put into usable form by working out logarithmic denominators of the equation for various ratios of thickness of insulation to diameter of conductor. This has been termed the *geometric factor*. Charging current of a three-core 3-phase cable is

$$I = \frac{3 \times 0.106EfK}{1000G_2} \quad \text{A/1000 ft} \quad (18-29)$$

For impregnated-paper cable, K is 3.3, and the equation for 60-Hz circuits becomes

$$I = \frac{3 \times 3.3 \times 0.106 \times 60E}{1000G_2} = 0.063 \frac{E}{G_2} \quad \text{amperes} \quad (18-30)$$

Values of G for single-conductor and G_2 for 3-conductor cable may be taken from Table 18-22.

Geometric Factors of Cables. See Table 18-22. Intermediate values may be found by interpolation.

TABLE 18-22 Table of Geometric Factors of Cables

Ratio $T + t$ d	G Single conductor	Sector factor	Three-conductor cables					
			G_1 at ratio t/T			G_2 at ratio t/T		
			0	0.5	1.0	0	0.5	1.0
0.2	0.34	...	0.85	0.85	0.85	1.2	1.28	1.4
0.3	0.47	0.690	1.07	1.075	1.08	1.5	1.65	1.85
0.4	0.59	0.770	1.24	1.27	1.29	1.85	2.00	2.25
0.5	0.69	0.815	1.39	1.43	1.46	2.10	2.30	2.60
0.6	0.79	0.845	1.51	1.57	1.61	2.32	2.55	2.95
0.7	0.88	0.865	1.62	1.69	1.74	2.55	2.80	3.20
0.8	0.96	0.880	1.72	1.80	1.86	2.75	3.05	3.45
0.9	1.03	0.895	1.80	1.89	1.97	2.96	3.25	3.70
1.0	1.10	0.905	1.88	1.98	2.07	3.13	3.44	3.87
1.1	1.16	0.915	1.95	2.06	2.15	3.30	3.60	4.05
1.2	1.22	0.921	2.02	2.13	2.23	3.45	3.80	4.25
1.3	1.28	0.928	2.08	2.19	2.29	3.60	3.95	4.40
1.4	1.33	0.935	2.14	2.26	2.36	3.75	4.10	4.60
1.5	1.39	0.938	2.20	2.32	2.43	3.90	4.25	4.75
1.6	1.44	0.941	2.26	2.38	2.49	4.05	4.40	4.90
1.7	1.48	0.944	2.30	2.43	2.55	4.17	4.52	5.05
1.8	1.52	0.946	2.35	2.49	2.61	4.29	4.65	5.17
1.9	1.57	0.949	2.40	2.54	2.67	4.40	4.76	5.30
2.0	1.61	0.952	2.45	2.59	2.72	4.53	4.88	5.42

Example. Find 60-Hz charging kVA for 33-kV cable having three 350,000-cmil sector-type conductors each with $^{10}/_{32}$ in of paper and a $^{5}/_{32}$ -in belt.

$$T = 0.313 \text{ in} \quad t = 0.156 \text{ in} \quad d = 0.681 \text{ in} \quad t/T = 0.5$$

$$(T + t)/d = (0.313 + 0.156)/0.681 = 0.69; E = 33/1.73 = 19 \text{ kV}$$

Interpolating in Table 18-22, we find $G_2 = 2.78$.

For sector-type cable, G_2 must be multiplied by the sector factor for 0.69, which is seen to be 0.86 in the sector-factor column in Table 18-22. For such a cable,

$$G_2 = 0.86 \times 2.78 = 2.39 \quad \text{and} \quad I = (0.063 \times 19)/2.39 = 0.5 \text{ A/1000 ft}$$

Charging kVA = $3IE = 3 \times 0.5 \times 19 = 28.5 \text{ kVA/1000 ft}$, and for a cable having a length of 20 mi it would be $20 \times 5.28 \times 28.5 = 3010 \text{ kVA}$. For single-conductor cables, $t = 0$ and $(T + t)/d = T/d$, which is used to get the value of G from the values for single-conductor cable in Table 18-22.

Cable Terminations. A cable termination must perform several functions:

1. Provide means for electrical connection of the cable to an equipment or circuit.
2. Control the electrostatic stresses so that there is no electrical-discharge activity in the termination at design voltage levels. One important consideration is to control the voltage stresses where the change is from a uniform radial field within the (shielded) cable to a new configuration beyond the termination of the shield. Other considerations are to provide adequate flashover and creepage strength to nearby grounds.
3. Prevent loss of gas or liquid insulation impregnant from the cable, where needed, or from the termination.

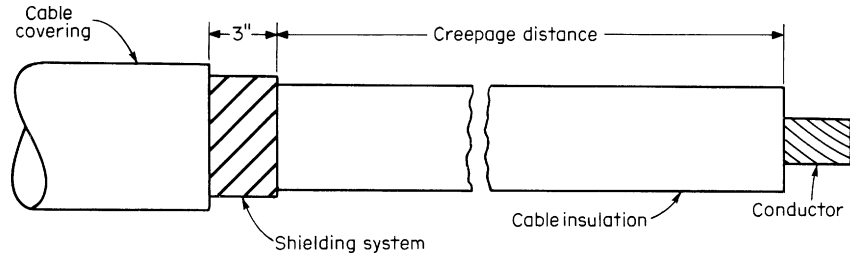


FIGURE 18-56 Elementary plain-shield termination.

4. Provide suitable mechanical and/or hermetic termination of the sheath, where used.
5. Serve as a load-break switch or separable connection, where needed.

Many types of terminations are in use, ranging from those made by hand in the field to factory-made types requiring very little work in the field. Two broad classifications are live-front and dead-front. The former involves exposed, bare electrical connections and possibly lengths of unshielded cable. The latter type of termination is completely enclosed in a semiconducting or metallic structure essentially at ground potential, such that it can be touched without hazardous shock while the equipment is energized.

Elementary Stress-Cone Termination. Figure 18-56 shows a single-conductor shielded cable prepared for termination. Figure 18-57 shows an elementary stress-cone termination. The stress cone may be built up by using tapes of a material compatible with the cable insulation, or it may be a factory-molded stress cone which is slipped over the (solid-dielectric) cable insulation system after the end of the cable has been properly dressed.

The stress cone serves to keep dielectric stresses at acceptable values. Without the stress cone, the plain termination of Fig. 18-56 would experience excessive stresses at normal voltage near the end of the shielding system, leading quickly to failure. Occasionally, an overall cover tape may be provided. Usually, a compression-type connector is installed on the cable conductor to provide a means of electrical connection to the equipment.

Separable Insulated Connectors. Accompanying the rapid growth in the use of single-conductor, concentric-neutral (or shielded cables employing solid-dielectric insulation) has been the development of separable insulated connectors of the dead-front classification. A typical termination consists of

1. An elbow, as shown in Fig. 18-45, which is physically and electrically connected to the end of a properly dressed cable.
2. A load-break switch module where the load-break function is specified (see Fig. 18-44).
3. An apparatus bushing. When a load-break module is not used, the elbow is mated directly to the apparatus bushings.

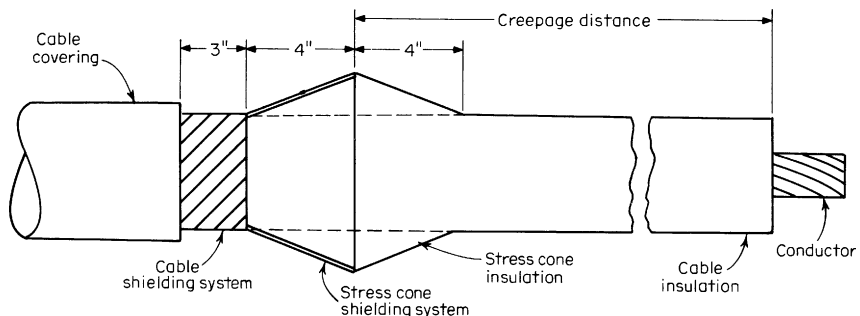


FIGURE 18-57 Elementary stress-cone termination.

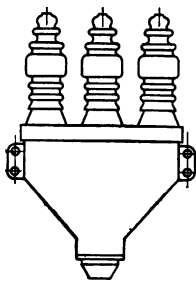


FIGURE 18-58 Three-conductor disconnecting-type pothead.

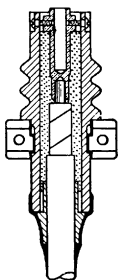
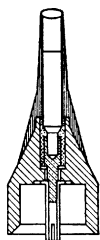


FIGURE 18-59 Disconnecting-type pothead.

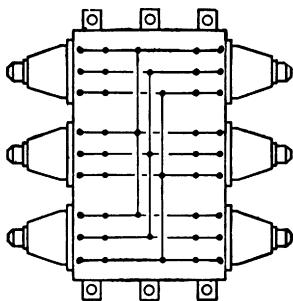


FIGURE 18-60 Six-way disconnecting cable-junction box.

The external shield and the insulation of the elbow and switch module are made of synthetic rubber. The stress-relief function is designed into the molded configuration.

When the elbow is in its normal connected position, the termination is dead-front and submersible.

A wide variety of accessory components are available, including multitaps, insulated bushings, feed-through bushings, insulating caps, etc. so that wide flexibility in operating procedures can be obtained for differing system and equipment configurations.

Separable insulated connectors are available in 200-A ratings for use on grounded-wye systems of the 15-, 25-, and 35-kV classes. Ratings of 600 A also are available, but these usually cannot be opened under load or while the cable is energized.

To install the elbow, the end of the cable is dressed according to the manufacturer's specifications; often a jig is used so that proper removal of semiconducting shield, correct dressing dimensions, exposure of the conductor, etc., are easily obtained. A crimped connector is then installed on the cable conductor, and the elbow is then slipped over the cable, internal male contact installed, and the cable or concentric neutral is connected to the semiconducting outer shield of the elbow.

Obviously, a termination of this kind can be installed much more quickly and with a lower level of skill needed than in terminating the traditional paper-insulated, lead-sheathed cables.

Pothead Terminations. Where cables are connected to overhead systems or to switchgear equipment, they often are terminated by means of potheads, such as that shown in Fig. 18-58. An extremely wide variety of types is in use, depending on

1. System voltage.
2. Type of cable insulation.
3. Single- or multiconductor cable.
4. Type of jacket or sheath.
5. Whether "live" side of pothead is outdoor or within an equipment. Some potheads are of the disconnecting type as indicated in Fig. 18-59.

There is an increasing trend toward the use of factory-made molded-rubber terminations in place of the traditional potheads, particularly with cables having solid-dielectric insulation.

Subway Junction Boxes. Subway junction boxes are sometimes used in cable systems to interconnect distribution circuits at points where it is desired that the connection be opened, at times, for construction or operating purposes and where overhead disconnecting facilities are not available. In low-voltage systems, such as 208Y/120-V secondary networks, such boxes may include sectionalizing fuses or connecting links. They are used in a number of different circuit configurations, a six-way junction box being shown in Fig. 18-60.

Splicing. Cable splices to a great extent resemble "back-to-back" portions of cable terminations. The completed splice provides

1. Electrical connection between the cable conductors, usually by means of crimped connectors.
2. Insulation over the exposed conductors and connector.
3. Jointing of the shielding or concentric neutral systems of the two cable sections so that electrical stresses are properly controlled.
4. Jointing of the jacketing systems or sheaths.
5. A "stop" function where the two cable insulation systems are different, for example, oil-impregnated paper on one side and solid dielectric on the other. Here it is necessary to contain the oil in the paper insulation and to exclude its penetration into the solid dielectric.
6. A disconnecting function, where required.

Factory-made splices are used extensively for splicing cables with solid-dielectric insulation. Where the disconnecting function is required, various combinations of multitaps and elbow terminations are used.

The traditional method of splicing paper-insulated, lead-sheathed cable is shown in Fig. 18-61. This method, which employs hand-wrapped insulating tapes, requires a high level of skill and training as contrasted to the use of factory-made splices for joining solid-dielectric cables. In jointing single-conductor cables, the lead sheath is removed about 6 in back from the end, and enough insulation is cut away to permit a soldered connection to be made. When the connection is complete, the bare parts are wrapped with tape until the equivalent of cable insulation has been applied. A lead sleeve which has previously been slipped over one of the cables is now wiped on the two cable sheaths so as to enclose the joint. Air space around the joint is then filled with hot insulating compound poured into a small hole in one end of the sleeve; a similar hole is left in the other end to allow air to escape. These holes are then closed by soldering. The joint should be allowed to cool before it is moved, so that the compound will hold the parts rigidly in place.

In jointing 3-conductor cables, the lead must be removed about 10 in to facilitate taping the conductors (see Fig. 18-61). In making joints for 6600 V and higher, it is important that as little air remain in taping as possible. If paper tape is used, each layer should have compound poured over it before the next is applied.

Installation of Cable. Generally, *direct-buried cable* in underground residential distribution (URD) systems is buried in a trench, usually 36 in or more deep. Often, random lay of the power and telephone cables is employed, with no intentional separation. When soil conditions permit, the trench is backfilled with the original material. In some cases a selected backfill and/or protective covering over the cables may be necessary.

Where URD circuits must be routed under streets or other paved surfaces, or in locations such that it would be impractical to dig in order to repair a faulted cable, duct installation often is used.

Where soil conditions and circuit configurations are favorable, it is possible to directly plow in the cable by means of a special plow which breaks the earth ahead of the cables and guides them into the furrow.

In *duct installations*, the most common method of preparation has been to use wood or metal rods which are pushed into the duct section by section as they are connected together. When the opposite end of the duct is reached, a wire is attached to the end of the last rod and is pulled into the duct as the rods are withdrawn.

When the duct is airtight, a piston with attached flexible wire can be blown through the duct by means of compressed air. This method is quicker and less laborious than the rodding process.

Cables are pulled through the duct by means of a pulling line, usually wire rope, and a power-driven cable-pulling winch. Cables of moderate size and length usually are pulled by means of cable

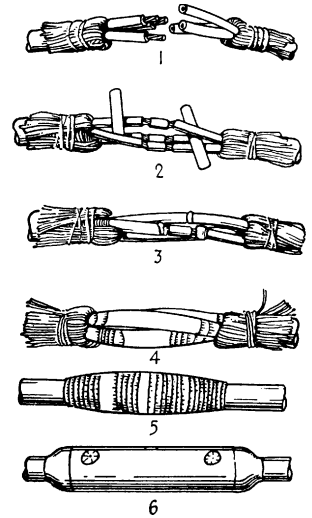


FIGURE 18-61 Successive stages in cable splicing.

grip, which is a type of woven-wire basket designed to increase its grip on the cable as the tension increases. Often a flexible pull-in tube is used in the manhole to prevent damage to the cable being pulled and to other exposed cables in the manhole.

With long sections or larger cables, it may be necessary to use a pulling eye rather than a cable grip because the pulling tension may exceed the capability of the cable grip. The pulling eye is a steel eye which usually is fastened directly to the cable conductors.

When a new cable is to be installed in an existing duct, it is generally desirable that the diameter of the duct be at least $\frac{3}{4}$ in greater than that of the cable. Where the duct section is exceptionally long or contains relatively sharp bends, a clearance of 1 in may be needed. On short, straight sections, $\frac{1}{2}$ -in clearance may be acceptable. Where several single-conductor cables are to be drawn into the same duct, the cable reels are set up in tandem and all cables are pulled into the duct simultaneously.

Cable Training. The location of cables in manholes is determined primarily by the ducts which they occupy. The cables should be fanned out as they leave their ducts so that they do not cross other cables or ducts. Sufficient length must be left in manholes to permit training on racks around the manhole walls, as shown in Figs. 18-52 and 18-53, and for joining. Radius of bends should be greater than the minimum safe bending radius for the cable, and cable movement also must be considered. The safe bending radius varies with the size, type of sheath or armor, etc. and generally is on the order of 8 to 12 times the overall diameter of the cable for power cables.

With large cables, the periodic load cycles cause repeated flexing and movement in the manholes, and duct-mouth protection is often used to prevent cracking of lead sheaths. This may consist of a piece of galvanized metal inserted under the cable and arranged to prevent the sheath from being pressed against the sharp edges of the duct mouth.

In order to limit damage resulting from cable faults to the failed cable, it is quite common to fire-proof the cables in a vault or manhole. Such fireproofing usually is done with asbestos tapes and asbestos or mortar cements.

Sheath Bonding. With cables having a lead or other metallic sheath, it is common practice to bond together the different sheaths in a manhole or vault. Bonding consists of electrically connecting together the various sheaths. Various types of bonding systems are in use to maintain the sheaths at a common potential near ground potential, thus reducing the danger to workers who may be in the manhole when a cable fault occurs. This also eliminates the possibility of serious arcing occurring between the sheaths of the faulted and unfaulted cables.

Selection of Duct Position for Cable. Cables used in local distribution should be installed in the top row of ducts so that manholes for service connections and lateral circuits can be of a relatively shallow construction. In distribution manholes, the higher-voltage cables and cables of through lines should be placed in the lower and outside ducts, where possible, and they should be trained with the least possible interlacing with other cables.

Ambient Earth Temperatures. Ambient earth temperatures vary with geographic location, season, and depth. Average daily air temperature at a given location follows a more or less sinusoidal curve over the seasons of the year. As a result, the earth ambient temperatures also exhibit an annual sinusoidal variation. At depths greater than 1 to 2 ft, there is essentially no daily variation in earth ambient, but there is a seasonal variation which is greater at shallow depths, decreasing with depth. In addition, as the depth increases, the variation in ambient temperature increasingly lags behind the daily ambient air temperature curve; at a depth of 6 ft, this lag may be as great as 6 to 8 weeks. At depths of 20 to 30 ft, the earth temperature remains practically constant at about the mean annual air temperature. As a result, the earth temperature tends to increase with depth in the winter and decrease with depth in the summer. At a depth of $3\frac{1}{2}$ ft, typical temperatures are as follows:

	Temperature, °C	
	Summer	Winter
Northern U.S.	20–25	2–15
Southern U.S.	25–30	10–20

Calculation of Ampacities of Cables. The precise calculation of ampacities of cables is extremely complex and has been the subject of numerous technical papers. This complexity is due not only to the characteristics of the thermal circuit, such as heat transfer through the cable insulation and sheath, transfer to duct or earth, and transfer from duct bank to earth but also to the fact that losses in the cable conductor are subject to skin and proximity effects. Also, additional losses can occur in the cable-shielding system depending on the nature of the installation.

Presently accepted methods of calculation, empirical data, and numerous references are treated in the following references:

1. IEEE Standard 835-1994, *IEEE Standard Power Cable Ampacity Tables*, goes into great detail explaining where the numbers came from. The types of cables for which ampacities have been calculated range from simple crosslinked polyethylene insulated 600-volt cables up to various medium voltage cables. The technical introduction covers cable construction, installation conditions, calculation methods, calculation examples and details of the assumptions made in calculating the ampacities that appear in the tables.
2. Ampacities, Including the Effect of Shield Losses for Single Conductor Solid Dielectric Power Cable 15 kV through 69 kV, NEMA WC 50-1976/ICEA P-53-426, 2nd ed. (R1993, R1999).

Maximum Allowable Conductor Temperature. The ICEA temperature ratings for polyethylene (thermoplastic) and cross-linked-polyethylene-insulated power cables are

Insulation	Max. conductor temperature, °C	
	Normal operation	Emergency overload
Polyethylene	75	90
Cross-linked polyethylene	90	130

Maximum conductor temperatures for impregnated paper-insulated cables are given in Table 18-23, as adapted from Publication P-46-426 of the IPCEA.

Ampacity of Cables. There is a growing use of single-conductor, solid-dielectric power cables for important 3-phase distribution circuits in the 15- to 35-kV class. Various shielding systems are in use including concentric wires, ribbons, and tapes. In many cases, on 4-wire primary-distribution circuits, the concentric wires are used as neutral conductors. When the shields are bonded together and grounded at multiple locations, circulating currents can flow in the shields, resulting in I^2R losses and appreciable heating effect. Such losses may be significant when the cables are spaced.

The AIEE-IPCEA ampacity tables do not include the effects of circulating-current losses, but these effects are included in the ampacity tables of IPCEA Publication P-53-426, NEMA Publication WC50-1976, "Ampacities Including Effect of Shield Losses for Single-Conductor Solid-Dielectric Power Cable 15 kV through 35 kV (Copper and Aluminum Conductors)." The ampacity data in Table 18-24 have been taken from this publication and apply to directly buried, solid-dielectric power cable.

Table 18-25 has been adapted from the IPCEA Publication P-53-426 (and NEMA Publication WC50-1976) to illustrate typical ampacities of single-conductor, solid-dielectric power cables installed in underground ducts. The type of installation is assumed to be directly buried fiber or plastic duct of inside diameter nominal pipe size to provide a minimum diametral clearance of 0.75 in between cable outside diameter and inside diameter of the duct. The assumed arrangement of the ducts is shown in Fig. 18-62.

TABLE 18-23 Maximum Conductor Temperatures for Impregnated-Paper-Insulated Cable

Conductor temperature, °C			
Rated voltage, kV	Normal operation	Emergency operation	
Solid-type multiple conductor belted			
1	85	105	
2–9	80	100	
10–15	75	95	
Solid-type multiple conductor shielded and single conductor			
1–9	85	105	
10–17	80	100	
18–29	75	95	
30–39	70	90	
40–49	65	85	
50–59	60	75	
60–69	55	70	
Low-pressure gas-filled			
8–17	80	100	
18–29	75	95	
30–39	70	90	
40–46	65	85	
Low-pressure oil-filled and high-pressure pipe type			
		100 h	300 h
15–17	85	105	100
18–39	80	100	95
40–162	75	95	90
163–230	70	90	85

Source: Copyright 1962 by Insulated Power Cable Engineers Association. Used by permission.

18.25 FEEDERS FOR RURAL SERVICE

Basic Conditions. Rural distribution differs from urban in that consumers are farther apart and load units are generally small. Since distances are great, the primary system voltage should be the 15-kV class or higher, and the load per mile being low requires the cost of feeder construction to be as low as is consistent with a reasonable degree of permanence and reliability. One transformer per customer is required in many cases. Rural construction since the late 1930s has made electric service available to practically every farm. Efforts are directed now to bolstering capacity to serve the growing loads.

Poles and Spans. Design of overhead lines for rural service differs from that of urban lines in several respects. Costs are reduced by using longer spans and as few accessories as possible. Longer spans mean greater sag and higher poles to get proper clearance at the low point of the span. The increase in sag may, however, be reduced by use of higher tensile stresses in conductors. This is possible when steel is employed in conjunction with copper or aluminum wires. Steel is combined with copper in a high-strength strand known as Copperweld, which has 30% or 40% of the conductivity of a copper conductor of equal size, or in a similar aluminum and steel conductor known as Alumoweld. When greater conductivity is needed, one or more strands of hard copper are stranded with or around the Copperweld or hard aluminum strands around Alumoweld. Steel is also stranded

TABLE 18-24 Ampacity of Single-Conductor Solid Dielectric Power Cable Installed Direct Buried

Cond. size	Neutral size	Ampacity	°C*	W/ft ²
1/0	Full	241	66	46.2
1/0	1/2	245	66	45.2
1/0	1/3	246	66	44.8
1/0	1/6	247	66	44.2
4/0	Full	339	71	47.4
4/0	1/2	349	70	45.7
4/0	1/3	355	69	44.8
4/0	1/6	361	69	43.6
500	1/3	513	75	45.5
500	1/6	544	74	43.1
500	1/12	566	73	40.9
500	1/18	575	72	40.2
750	1/3	575	75	42.3
750	1/6	624	75	40.8
750	1/12	671	74	38.5
750	1/18	690	73	37.2
1000	1/6	675	76	39.8
1000	1/12	748	76	37.9
1000	1/24	799	75	35.6
1000	1/36	819	74	34.8

90°C aluminum conductor.

Single circuit—three cables spaced.

25°C earth ambient.

90 rho soil resistivity.

*Corresponding earth interface temperature in °C.

Source: From IEEE Std 835-1994 (© 1994 IEEE).

with aluminum wires into ACSR conductor. Such types of conductor have ample conductivity for rural lines, and they have been used widely. In level country, spans of 400 to 600 ft are practical, while in hilly country, spans of 800 to 900 ft are occasionally possible.

Cable. Design of underground circuits for rural service is similar to that of urban underground circuits. Concentric-neutral cables are likely to be used in both types of systems. Because the rural circuits have longer uninterrupted runs of cable, there is a better opportunity to plow in the cable rather than digging trenches. Plowing results in lower installed costs per unit length of cable. In fact, some electric suppliers report that the total cost of a rural underground system is less than the cost of an overhead system to serve the same load.

Location of Circuits. Rural-service circuits are run along main highways, where the largest number of users may be reached. Branches along intersecting roads are extended as may be warranted by service requirements. In some cases, private rights of way, maintained for transmission lines, may be utilized.

Voltage. Rural circuits may be extended 5 to 50 mi from the point of supply, and voltage used for primary distribution must be chosen accordingly. Loadings are often so small that the minimum size of conductor required for dependable strength for overhead or cable insulation for underground is sufficient to meet requirements of voltage drop and line loss. This is particularly true when the higher voltages are used.

The most common primary voltage used in rural areas is 12,470Y/7200 V, 4-wire for normal load densities and 24,940Y/14,400 V for very light load densities. There is a trend toward using both 24,940Y/14,400 V and 34,500Y/19,900 V for all types of rural areas.

TABLE 18-25 Ampacity of Single-Conductor Solid Dielectric Power Cable Installed in Underground Ducts

Cond. size	Neutral size	Ampacity 75% LF	Ampacity 100% LF
250	1/3	272	239
250	1/6	279	245
250	1/12	282	249
250	1/18	284	250
350	1/3	316	277
350	1/6	329	288
350	1/12	337	295
350	1/18	339	298
500	1/3	364	317
500	1/6	386	337
500	1/12	402	351
500	1/18	407	356
750	1/3	414	359
750	1/6	449	389
750	1/12	480	417
750	1/18	493	428
1000	1/6	490	424
1000	1/12	536	464
1000	1/24	571	494
1000	1/36	584	506

90°C aluminum conductor.

Two circuits—three cables spaced 7.5 inches.

25°C earth ambient.

90 rho soil resistivity.

Source: From IEEE Std 835-1994 (© 1994 IEEE).

Single-phase circuits are most economical for the usual light loads found in rural areas and where power units do not exceed 10 hp. Vee-phase circuits consisting of 2-phase conductors and the neutral are an economical method of supplying 3-phase loads using open-wye-open-delta transformer banks. Full 3-phase, 4-wire construction will be desirable for many areas. In some cases there may be relatively small 3-phase loads in a single-phase area. Often these loads can be supplied economically from a single-phase system by means of a phase converter, the output of which is 3-phase voltage.

Limitations of voltage and distance are illustrated by the following table showing kilowatt-miles corresponding to a 5% line drop at 80% power factor for a circuit of 1/0 ACSR, or its equivalent in other metals.

Kilowatts $\times$ miles for 5% voltage drop, power factor 80%

System	4.16 kV	12.47 kV	24.94 kV	34.5 kV
Single-phase	82	737	2949	5646
3-phase	488	4375	17919	33815

Values for other sizes are approximately in proportion to relative cross section. In order to determine specific voltage-drop values for 3-phase overhead and underground circuits, refer to Table 18-3.

Conductors and Spans. Because of the economy of using long spans, the choice of span lengths and conductor strength is of much importance in planning rural lines. Single-phase lines are commonly taken from a 3-phase system with neutral grounded. The grounded conductor is carried on a

bracket about 2 ft below the phase wire, which rests on an insulator carried on the top of the pole. No crossarm is required, except on a main line of more than one phase.

While the conductivity of No. 4 ACSR or Copperweld may be thermally adequate for the greater part of a rural system, system economics can dictate the use of larger conductors. The strength of No. 4 ACSR or Copperweld is usually ample for spans of 350 to 600 ft, depending upon design-loading conditions. Conductors should be sagged in accordance with the conductor manufacturer's recommendations.

Poles. The strength of poles should be determined for the height required by the methods described in Secs. 18.14 and 18.15. The length of poles required in any situation must be such as to allow for depth of setting and height of wire supports needed to give proper clearance above ground at the low point of the span. Such clearances should be not less than value shown in the NESC. In the case of road and railroad crossings, the necessary clearance may sometimes be more readily had by placing one end of the span near the crossing, thus avoiding having the low part of the span over the crossing. In rolling or hilly areas, it is desirable to locate poles on higher elevations to permit use of longer spans and greater sags.

Where no ice loading is likely, 30-ft poles can be used for two conductors of a single-phase branch on level ground or on long even slopes with span lengths to 400 ft. This often will preclude, however, the addition of communication circuits to the poles. Where ice and wind loading is expected with some regularity, it is necessary to use 35-ft poles for spans exceeding 300 ft. At corners or angles, poles should be supported by guying or bracing to support unbalanced longitudinal stresses.

Crossarms or equivalent equipment are required for the main 3-phase circuits and for lines supplying any user taking 3-phase service for power. A two-pin arm is often used with the third phase on the pole top. The grounded neutral is carried on the side of the pole about 2 ft below the arm.

Transformer Installations. Transformers usually supply not more than one or two customers, and sizes, therefore, are small compared with the average used in urban work, 10 to 15 kVA being average for single-phase installations. Where points of use are more than about 500 ft apart, it is usually most economical to provide separate transformers. When two users are within this distance, they can be served by placing a transformer between them and constructing a secondary. Rural loads on some systems have grown to the point where 15- and 25-kVA transformers are required.

Transformer capacity usually may be selected on the basis of loading the transformer to 150% of nameplate rating for peak loads lasting for 1 to 2 h. Pumping for drainage or irrigation is likely to require rated capacity more nearly equal to load.

Stray Voltages. Stray voltages on dairy farms may cause lowered milk production and increased mastitis in dairy cattle. Dairy cattle are particularly sensitive to low magnitudes of voltage. Voltages on the order of 0.5 V occurring between metal stanchions or metal drinking cups and the concrete floor may be troublesome. It should be noted that the same symptoms may be due to other causes and that stray voltages are not always to blame.

One characteristic of the common-neutral distribution system, in which the neutral conductor is common to both the primary and secondary systems, is the multiplicity of ground connections between the neutral conductor and earth. Unbalanced load conditions on either the farm secondary system or the utility primary system result in current flow in the neutral conductor. Due to the multiplicity of ground connections, some portion of the neutral current flows in earth. These earth currents

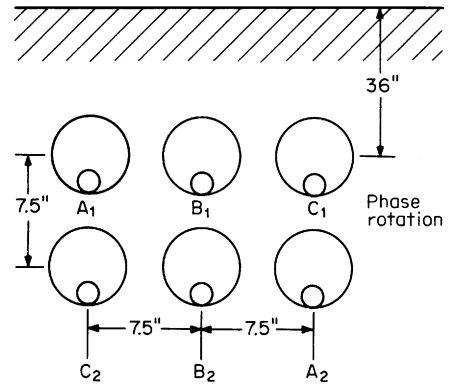


FIGURE 18-62 Arrangement of ducts.

cause stray voltages to appear in the earth. Deteriorated insulation on farm wiring and machinery can also cause earth currents, and these causes should be eliminated first.

One way to minimize stray voltages in the dairy barn is to cast wire mesh into the concrete floor and to bond the mesh and all metal structures together to establish equal potentials. In cases where current flow in the utility primary neutral is identified as a cause of stray voltages, it may be necessary to isolate the primary and secondary neutrals of the distribution transformer serving the farm. The NESC, IEEE C2-1997, addresses this situation in Section 97D.

18.26 DEMAND AND DIVERSITY FACTORS

Demand Factor. The ratio of maximum demand to total load connected, expressed as a percentage, is termed the *demand factor* of an installation. For example, if a residence having equipment connected with a total rating of 6000 W has a maximum demand of 3300 W, it has a demand factor of 55%. Demand factors of various types of large loads are helpful in designing systems, particularly those in buildings. As an example, a single household electric clothes dryer, of course, has a demand factor of 100%, but 25 dryers in a group have a demand factor of 33%. Similarly, three to five all-electric apartments in a multifamily dwelling have a demand factor of 45%. The lower the demand factor, the less system capacity required to serve the connected load. However, summer air conditioning and winter electric heating are loads that make for high demand factors.

Coincidence or Diversity Factor. The *coincidence factor* is defined as the ratio of the maximum demand of the load as a whole, measured at its supply point, to the sum of the maximum demands of the component parts of a load. The *diversity factor* is the reciprocal of the coincidence factor. Coincidence factors can be applied to known consumer demands for estimating the loading of distribution transformers, lines, and other facilities.

Coincidence factors for residential consumers can vary over a wide range for different types of consumers. The coincidence factor for a large group of consumers with no major appliance might be as low as 30%, whereas a group of electric-heating consumers might be as high as 90%.

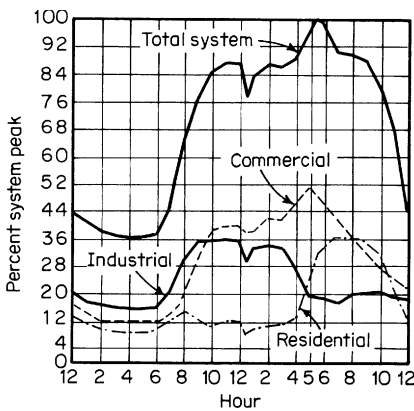


FIGURE 18-63 Characteristic metropolitan load pattern.

Diversity Between Classes of Users. The *daily-load curve* of a utility is a composite of demands made by various classes of users. The load curve on the day of maximum total system peak occurs when class loads gang up to create this maximum demand for the year. This is not necessarily the day, and usually is not the day, of any particular class peak. Class load curves on the day of system peak are illustrated in Fig. 18-63.

Air-conditioning loads have shifted these curves for many systems to cause daytime peaks during hot weather in the summer. Electric house heating builds heavy morning and evening loads during cold weather

in the winter.

Diversity in the Feeder System. The diversity of demands of transformers on a radial feeder makes the maximum load on the feeder less than the sum of the transformer loads. The diversity factors of a feeder vary greatly depending on load conditions. Some typical diversity factors are given in Table 18-26. The diversity factor of lighting feeders ranges from 1.1 to 1.5, while that of

TABLE 18-26 Diversity Factors

Elements of system between which diversity factors are stated	Diversity factors for			
	Residence lighting	Commercial lighting	General power	Large users
Between individual users	2.0	1.46	1.45	
Between transformers	1.3	1.3	1.35	1.05
Between feeders	1.15	1.15	1.15	1.05
Between substations	1.1	1.10	1.1	1.1
From users to transformer	2.0	1.46	1.44	
From users to feeder	2.6	1.90	1.95	1.15
From users to substation	3.0	2.18	2.24	1.32
From users to generating station	3.29	2.40	2.46	1.45

mixed light-and-power feeders is likely to be 1.5 to 2 or more. At the substation there is also a diversity factor of 1.05 to 1.25 between the sum of feeder maxima and the substation maximum. A large system has a further diversity factor between substations of 1.05 to 1.25. Total diversity factors in a large system are somewhat as in Table 18-26.

18.27 DISTRIBUTION ECONOMICS

Economic Comparisons. The most straightforward and generally applicable technique to use in distribution system investment problems is that of making economic comparisons on the basis of the present value of all future annual costs. That is, the economic choice is the one with the lowest present value of all future costs. With this as a criterion, the procedure for making an economic comparison between alternatives is a simple two-step operation, that is,

1. Estimate for each alternative the annual costs for each year.
2. If annual costs are not uniform, calculate their present value.

Time Value of Money. Money does have time value, and rent or interest on its use has to be paid. It is obvious that an alternative which requires the least expenditure immediately would be best, everything else being equal.

The process of taking money and finding its equivalent value at some future time is called a *future worth* or *future value* calculation. This calculation is the same as that used in determining the effect of compound interest.

If 8% is the established interest rate, then \$100 today is equivalent to $\$100(1 + 0.08)$ or \$108 a year from now, and $100(1 + 0.08) + 100(1 + 0.08) \times 0.08 = 100(1 + 0.08)^2$ 2 years from now and $100(1 + 0.08)^{10}$ 10 years from now. The expression $(1 + i)^n$ is called the *single-payment compound amount factor*, where i is the interest rate and n is the number of years. These factors and others are readily available for various interest rates and number of years in economic books such as *Principles of Engineering Economy* by Eugene L. Grant.

It should be noted that the use of 8% for the interest rate is for illustrative purposes only. The actual interest rate to use will be determined by the economic conditions at the time.

Hence, to find the future worth of \$100, 10 years later in the preceding example, first look up the compound amount factor in the 8% interest table for year 10; then multiply it by 100. The compound amount factor for this case is 2.159, and the future worth calculates to be $100(2.159) = \$215.90$.

The process of finding the equivalent value of money at some earlier time is called a *present worth* or *present value* operation. The present worth calculation is the reverse of the future worth

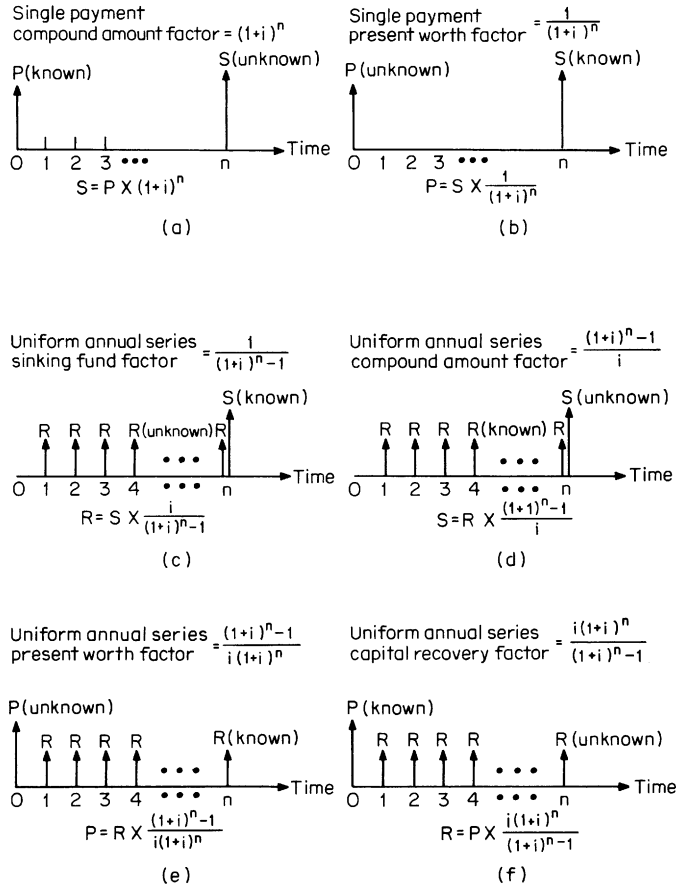


FIGURE 18-64 Graphic interpretation of compound interest factors.

calculation. If \$100 today has a future worth a year from now of \$108, then we can also say that \$108 a year from now has a present worth of \$100 today. The present worth factor is the inverse of the future worth factor, and it also may be found in interest tables. Since the future worth factor for n years is $(1+i)^n$, where i is the interest rate, the present worth factor is $1/(1+i)^n$.

To determine the present worth, as of today, of a \$100 cost anticipated to be incurred 2 years from now where the interest rate is 8%, first the present worth factor of 0.8573 is obtained from interest tables. Then multiplying this factor by \$100 gives the present worth of $100(0.8573) = \$85.73$.

Formulas for calculating the compound interest factors and a graphic interpretation of these factors are shown in Fig. 18-64.

Annual Charges. It is desirable to have a convenient method of calculating the annual costs of capital investments made in an alternative scheme. Fortunately, this can be done by using a level carrying charge which is expressed as a percentage of the original investment.

The total revenue requirements of a piece of equipment are the sum of the annual charges for

1. Return on investment
2. Depreciation
3. Income tax

4. Property taxes
5. Insurance
6. Operating and maintenance expenses

The first five of these charges can be conveniently estimated as a percentage of original investment. The operating and maintenance charges should be estimated separately for each project because they do not relate to capital investment as a percentage.

Level Annual Carrying Charges. The level annual carrying charge is the percentage by which the capital investment can be multiplied to determine its annual cost on a uniform basis. The value of this carrying charge is very much dependent on the expected life of the piece of equipment because depreciation varies in accordance with life expectancy. A method of obtaining the level annual carrying charge is as follows: (1) calculate the sum of the annual charges for return on investment, depreciation, income tax, property tax, and insurance for each year of the expected life of the piece of equipment; (2) use the appropriate present worth factor with each annual cost to convert the annual cost to a present worth value; (3) sum up these values to obtain the total present worth of the annual carrying charges; and (4) multiply the total present worth by the capital recovery factor (see Fig. 18-64) to get the equivalent uniform annual charge. Figure 18-65 shows graphically the actual and equivalent carrying charges for a capital investment of a piece of equipment with a 5-year life and an assumed 8% cost of money.

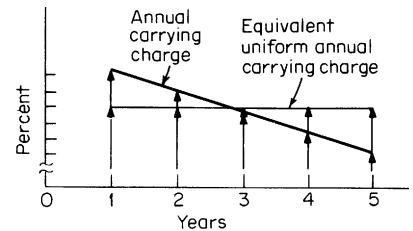


FIGURE 18-65 Representation of carrying charges.

The total carrying charges with 8% cost of money for various service lives are estimated as follows:

Years of life	Level annual total carrying charge in %
5	30.82
10	20.59
15	17.44
20	16.04
25	15.34
30	14.96
35	14.76
40	14.67
45	14.63
50	14.63

Operating and Maintenance Expenses. This cost component varies with the nature of the project. It is usually not a direct function of the capital invested and may have an inverse tendency. That is, alternatives often exist for higher capital expenditures to reduce operating costs. Therefore, it is *not* expressed as a percent of capital investment in most cases. Nevertheless, it should be included in annual costs.

Study Period. When determining the economic comparison of alternates by comparing the present worth of annual costs, the study period should be taken to the point that the alternates are equivalent in capability. If this is not practical, the study should be taken so far into the future that the difference in present worth would be insignificant.

Economic Evaluations. A simple example will show a comparison between two alternatives. Let *CC* represent the capital investment multiplied by the level annual carrying charge, *O&M* represent

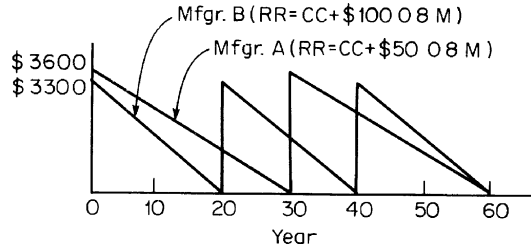


FIGURE 18-66 Time diagram.

annual operation and maintenance, and RR represent the total revenue requirement necessary annually to carry the project. A pad-mounted sectionalizing switch is needed for an underground circuit. The choice is between two manufacturers who can supply the switch but with different characteristics as follows:

	Mfr. A	Mfr. B
Installed cost	\$3600	\$3300
Operating and maintenance	50/year	100/year
Expected life	30 years	20 years

There is no salvage value at end of life. Determine which alternative is less expensive. The first step is to draw a time diagram like Fig. 18-66. The common point in time for the two alternatives is 60 years, so two cycles of A should be compared with three cycles of B.

Present worth analysis:

$$\begin{aligned}
 \text{PW mfr. A alternative} &= 3600 \times 0.1496 \times 11.258 + 50 \times 11.258 \\
 &\quad + (3600 \times 0.1496 \times 11.258 + 50 \times 11.258) 0.0994 \\
 &= 6063.11 + 562.90 + 658.63 \\
 &= 7284.64
 \end{aligned}$$

$$\begin{aligned}
 \text{PW mfr. B alternative} &= 3300 \times 0.1604 \times 9.818 + 100 \times 9.818 \\
 &\quad + (3300 \times 0.1604 \times 9.818 + 100 \times 9.818) 0.2145 \\
 &\quad + (3300 \times 0.1604 \times 9.818 + 100 \times 9.818) 0.0460 \\
 &= 5196.86 + 981.80 + 1325.32 + 284.22 \\
 &= 7788.20
 \end{aligned}$$

where 3600 = installed cost of mfr. A switch

0.1496 = level annual carrying charge for 30-year A switch

11.258 = 8%, 30-year uniform annual series present worth factor

50 = O&M of A switch

0.0994 = 8%, 30-year single-payment present worth factor

3300 = installed cost of mfr. B switch

0.1604 = level annual carrying charge for 20-year B switch

9.818 = 8%, 20-year uniform annual series present worth factor

100 = O&M of B switch

0.2145 = 8%, 20-year-single payment present worth factor

0.0460 = 8%, 40-year-single payment present worth factor

Manufacturer A switch would be the overall lowest cost and would be the better deal provided the capability and reliability of the two switches are equivalent.

18.28 DISTRIBUTION SYSTEM LOSSES

About 8% of the total output of a large power system is lost or unaccounted for. Much of this loss is in the distribution system. Since investment must be made in facilities to supply these losses, they should be an important consideration in the engineering design of the system. A knowledge of their magnitude is essential and they should not be omitted from overall comparisons of alternative facilities without a study of each specific situation.

Line Losses. The line losses, which are the sum of the I^2R , or resistance losses, can be easily found when the currents at peak load are known. Simplifying assumptions often can be made in making these calculations. For instance, if the load can be considered as being uniformly distributed, the losses are the same as if the total load were concentrated at a point one-third of the way out on the feeder.

Transformer Losses. Transformers have a no-load loss as well as a load loss. The transformer no-load loss is independent of load, whereas the load loss will vary as the square of the current. These losses for distribution transformers are usually published as no-load and total loss when the transformer is operating at rated voltage and rated kVA. The load loss at full-load current is the difference between total and no-load losses.

Working Principles. The problem of converting kWh of lost energy to dollars and cents has resulted in considerable controversy among system operators because of the difficulty of determining the value of the energy. It is not the purpose of this handbook to take sides in the controversy but rather to show the principles involved so that engineers will be able to evaluate losses using appropriate system costs.

The cost of supplying losses can be broken down into two major parts:

1. Energy component, or production cost to generate kWh losses
2. Demand component, or annual costs associated with system investment required to supply the peak kW of loss

The two components of cost usually are combined into a single figure either in terms of cents per kilowatthour of total energy loss or as dollars per kilowatt of peak loss. Expressing losses in terms of dollars per kilowatt is usually called *capitalized* cost of losses, and it has some advantage in that it shows directly the amount of money that could be economically spent to save 1 kW of loss. However, the expression of cost of losses in cents per kilowatthour is usually a more convenient form to use in most engineering studies.

The cost of losses depends on the point in the system at which they occur. The farther out on the system, the greater value losses have. One kilowatt of loss saved on the secondary system is worth more than 1 kW loss at generation because of the cumulative effect of increments of losses as they pass through various elements of the system.

In calculating loss, present-day or future cost of system investment should be used. The primary interest is to find the incremental investment, in dollars, required to supply an incremental load in kilowatts.

Opinions differ widely as to the degree to which the demand component of losses shall be evaluated. This ranges all the way from the dollar cost per kilowatt for future system expansion to no value at all for this component. The great majority of utility engineers prefer to assign full value to the demand component of losses.

Responsibility Factor. Owing to diversity between classes of loads (i.e., residential, industrial, etc.) on a distribution system, peak loads on distribution, transmission, and generation usually do not

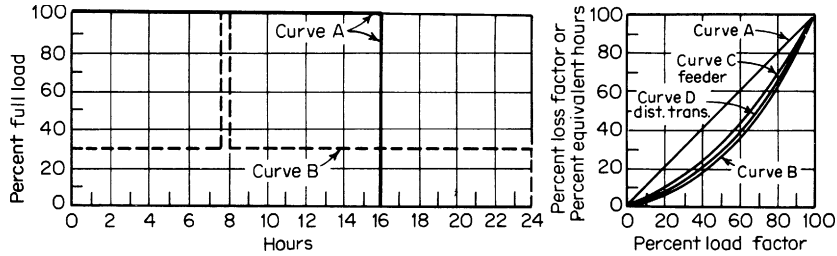


FIGURE 18-67 Relationship between load factor and loss factor or equivalent hours.

occur at the same time. Therefore, a loss which contributes 1 kW to the distribution system peak might contribute less than this to transmission and production plant peak because its maximum does not occur at the same time as the transmission or generation peak. This introduces *peak responsibility factors* used for evaluating cost of losses in various parts of the system.

Loss Factor. If the peak conductor losses of line or transformer have been calculated, it will still be necessary to know the loss factor or percent equivalent hours before it is possible to calculate the actual losses over a period of time. *Loss factor* is usually defined as the ratio of the average power loss, over a designated period of time, to the maximum loss occurring in that period. The term can refer to any part or all of the electric system. It is sometimes referred to as the *load factor of the losses*.

A corollary to loss factor is the term *equivalent hours*. This is defined as the number of hours per day, week, month, or year of peak load necessary to give the same total kilowatthours of loss as that produced by the actual variable load over the selected period of time. The period of time for distribution studies is usually 1 year, and it is obvious that *percent equivalent hours* has the same meaning as the term *percent loss factor*.

Relation Between Loss Factor and Load Factor. Definitions of *loss factor* and *load factor* are quite similar. (*Load factor* is defined as the ratio of average power demand over a stipulated period of time to the peak or maximum demand for that same interval.) Care should be taken that the latter is not used in place of loss factor when considering system losses. There is a relationship between the two factors which depends on the shape of the load curve. Because resistance losses vary as the square of the load, it can be shown that the value of loss factor can vary between the extreme limits of load factor and load factor squared. A number of typical load curves have been studied to determine this relationship for distribution feeders and distribution transformers. The relation is shown in Fig. 18-67. Note that loss factor is always less than load factor except where they are both unity, as would be the case for transformer core losses. The relationship between load factor and loss factor at the distribution transformer can be expressed by the empirical formula

$$\text{Loss factor} = 0.15 \text{ load factor} + 0.85 (\text{load factor})^2$$

It should be noted that when the shape of the load curve is known or can be reasonably estimated, the loss factor should be calculated directly and not determined by the empirical formula.

Cost of Losses. The two parts of the cost to supply losses are as follows:

$$\text{Energy component} = 8760 F_L E$$

$$\text{Demand component} = F_S P$$

where F_L = loss factor of load

E = cost of energy, dollars/kWh

F_S = responsibility factor

P = annual cost of system capacity, dollars/kW · year

Annual cost of losses can be combined into one value, in terms of either dollars per kilowatthour or dollars per kilowatt-year of peak loss, with the following formulas:

$$\text{Cost of losses, \$/kWh} = \frac{F_s P}{8760 F_L} + E$$

$$\text{Capitalized cost of losses, \$/kW-year} = F_s P + 8760 F_L E$$

18.29 STREET-LIGHTING SYSTEMS

Characteristics. The lighting of streets, parkways, and other roadways is about the only service in which the electric utility is often responsible for the utilization equipment. This involves the complete service of installation, maintenance, and operation of lighting systems during the hours of darkness (approximately 4000 h/yr) when they are required. Series (constant-current) circuits, historically a common supply for street lighting, have become obsolete.

Multiple Circuits. Street-lighting units today are normally supplied directly from the local distribution (120/240 V). The high-intensity-discharge lamps used have compatible ballasts for all common voltages, 120, 208, 240, 277, 480 V, designed to strike an arc within the light source and provide stable operating conditions. Ballasts may be high-power-factor or normal-power-factor types. Photoelectric controls are most frequently used integrally with individual lights but also may be used to switch contactors controlling circuits used for lighting only. An example of this is highway lighting where extended systems from a power-supply point are normally designed with 480 V.

Lamps and Luminaires. Present street-lighting systems are designed using high-intensity-discharge sources. The three principal types are clear or phosphor-coated mercury, metal halide, and high-pressure sodium. These lamps are available in several sizes ranging from less than 100 to 1000 W. Metal halide is not widely used because of its short life and poor lumen maintenance. Mercury lighting was the most popular type, since it was used extensively to replace older incandescent and fluorescent systems in the recent past. However, high-pressure sodium is the newest and most efficient lamp available. Its efficiency is over twice as high as mercury. The compact arc also allows for better control of the light distribution by the luminaire. The higher lamp efficiency and better control reduce the street-lighting power requirements to less than half that required for mercury. High-pressure sodium is taking over as the leading lighting system because of its economics.

Luminaires are sealed and also can be filtered. This minimizes the light loss due to dirt collecting in the luminaire. This is done to match the luminaire dirt depreciation so it matches the 4-year lamp life and minimizes the cleaning required during relamping.

There is a large variety of street-lighting equipment. This is required to fit different mounting heights, street widths, and lamp wattage. There are also differences in daytime appearance that are needed to fit the needs of the environment.

Underground Systems. While most utility-owned lighting systems were originally attached to existing wood-pole overhead distribution lines, these convenient supports are increasingly on rearlot lines or nonexistent (underground distribution). This means that public lighting systems must be designed with underground supply run from the nearest transformer, joint trench, or handhole. Integrating the street-lighting circuits properly with the overall underground system from the outset is essential for proper economics and cost control.

18.30 RELIABILITY

Reliability has always been a major consideration for utilities. In recent years there has been even more interest because loads are becoming more sensitive to even small system disturbances and concern has been expressed that deregulation, with associated cuts in personnel and budgets, will negatively impact system reliability. Distribution reliability is in a state of change. Some of these changes are

- Standardization of indices.
- Mandatory indices in some states.
- Performance-based rates.
- Sags and momentaries equaling outages for some loads.
- Contract penalties for interruptions, sags, etc.
- Maintenance budgets being reduced.

There are many ways to measure reliability. Some of the more common indices used by utilities are CAIDI, SAIDI, and SAIFI, as illustrated in Fig. 18-68.

These three indices are defined for sustained interruptions of 5 minutes or longer:

SAIFI [system average interruption frequency index (sustained interruptions)]. The system average interruption frequency index is designed to give information about the average frequency of sustained interruptions per customer over a predefined area. In words, the definition is:

$$\text{SAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}$$

To calculate the index, use the following equation:

$$\text{SAIFI} = \frac{\sum N_i}{N_T}$$

SAIDI (system average interruption duration index). This index is commonly referred to as Customer Minutes of Interruption or Customer Hours, and is designed to provide information about the average time the customers are interrupted. In words, the definition is:

$$\text{SAIDI} = \frac{\sum \text{customer interruption durations}}{\text{total number of customers served}}$$

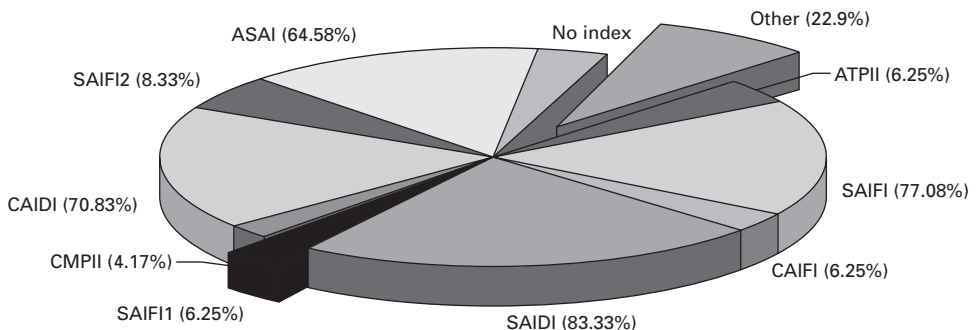


FIGURE 18-68 Percentage of companies using reliability indices (48 companies responded to survey).

To calculate the index, use the following equation:

$$\text{SAIDI} = \frac{\sum r_i N_i}{N_T}$$

CAIDI (customer average interruption duration index). CAIDI represents the average time required to restore service to the average customer per sustained interruption. In words, the definition is:

$$\text{CAIDI} = \frac{\sum \text{customer interruption durations}}{\text{total number of customers interruptions}}$$

To calculate the index, use the following equation:

$$\text{CAIDI} = \frac{\sum r_i N_i}{\sum N_i} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

Values of these indices vary widely depending on many factors, including climate (snow, wind, lightning, etc.), system design (radial, looped, primary selective, secondary network, etc.), and load density (urban, suburban and rural). Typical values seen by utilities in the United States are

SAIDI	SAIFI	CAIDI
96 min/yr	1.2 int/yr	80 min/yr

Some utilities are already measuring indices to reflect system disturbances, other than interruptions, that cause sensitive loads to misoperate. One of these, the momentary average interruption-event frequency index (MAIFI_E), is an index to record momentary outages caused by successful reclosing operations of the feeder breaker or line recloser. This index is very similar to SAIFI, but it tracks the average frequency of momentary interruption events. In words, the definition is:

$$\text{MAIFI}_E = \frac{\text{total number of customer momentary interruption events}}{\text{total number of customers served}}$$

To calculate the index, use the following equation:

$$\text{MAIFI}_E = \frac{\sum \text{ID}_E N_i}{N_T}$$

Note. Here, N_i is the number of customers experiencing momentary interruptions events and ID_E equals interrupting device events during reporting period. This index does not include the events immediately preceding a lockout.

Another proposed index to reflect voltage sags caused by faults on other parts of the system is the system average rms (variation) frequency index_{Threshold} ($\text{SARFI}_{\%V}$). This index records the number of specified short-duration rms variation per system customer. Voltage threshold allows assessment of compatibility for voltage-sensitive devices. To calculate the index, use the following equation:

$$\text{SARFI}_{\%V} = \frac{\sum N_i}{N_T}$$

where $\%V$ = rms voltage threshold 140, 120, 110, 90, 80, 70, 50, 10

N_i = number of customers experiencing rms < $\%V$ for variation i (rms > $\%V$ for $\%V > 100$)

N_T = total number of system customers

It is inevitable that more and more utilities will adopt some of these so-called power quality indices as their customers demand even better power for their sensitive loads.

In these days of reduced budgets, when utilities are being required to increase reliability, some of the techniques which cost very little or even nothing to achieve the goal of greater power quality are as follows:

- Purchase better-quality equipment.
- Shorten lead lengths on arresters.
- Use open-tie protection on underground systems.
- Use higher fuse ratings for transformers and laterals.
- Increase the number of homes per transformer.
- Pay attention to proper grounding.
- Use predictive reliability computer analysis to optimize designs.

18.31 EUROPEAN PRACTICES

In a time of deregulation and privatization, it has become common practice for a utility in one part of the world to own a utility in another country. While generation and transmission have relatively similar practices in all parts of the globe, distribution practices are considerably different depending on whether the system is based on American or European practices and standards. The following is a brief comparison of the two systems to familiarize engineers with the fact that in many ways distribution system operation and philosophy are so varied that direct comparison becomes extremely difficult.

Voltage Levels. In the United States, primary voltage levels can be just about anything. Figure 18-69 shows some of the more common voltage levels in the United States, with 13.8 kV probably being the most popular for the distribution primary. European voltage levels are much more standardized. Thus 30, 20, and 10 kV are used throughout the world where European standards are practiced.

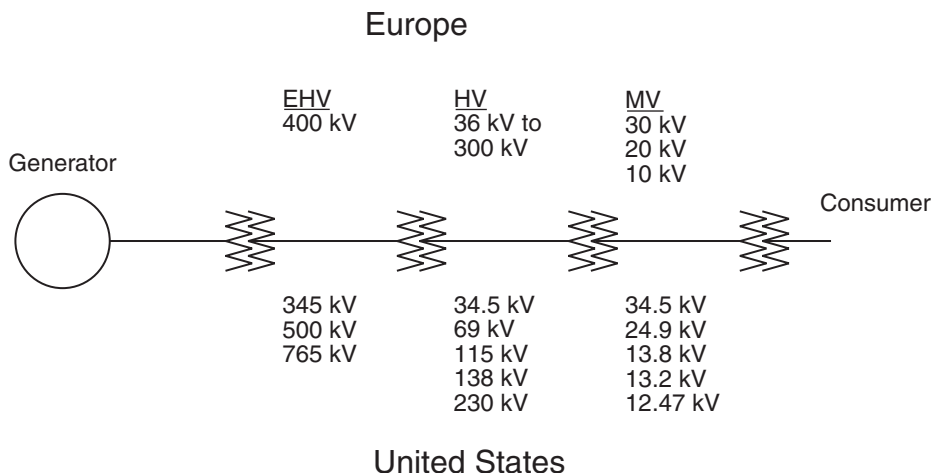


FIGURE 18-69 European and U.S. primary voltage levels.

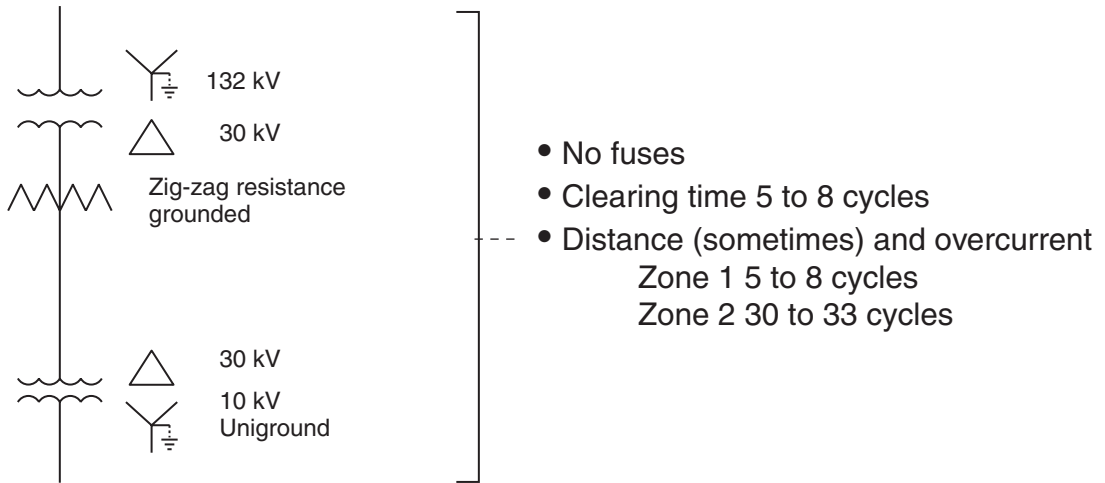


FIGURE 18-70 European distribution system grounding practices.

30-kV/10-kV Distribution. Figure 18-70 is a typical European system design, showing a unigrounded system at the 10-kV level where most of the distribution loads are supplied. This voltage level tends to be radial but can be networked. The 30-kV system, on the other hand, tends to be looped and is a 3-wire delta system sometimes using a grounding transformer to facilitate overcurrent protection.

Residential Distribution. Table 18-27 illustrates some of the major differences in philosophy between the two designs which makes comparison difficult. The major difference is that European practice tends to use 3-phase transformers with a much larger kVA rating to supply many more homes. Higher-density loads and higher secondary voltages are part of the reason for this difference.

Distributed Resources (DR) on the Distribution System. Distributed resources is a term which includes a variety of small generation technologies, including fuel cells, photovoltaics, microturbines, reciprocating engines, wind turbines, etc., with and without battery storage, which could be installed on the distribution system. In addition, many of these resources are becoming more

TABLE 18-27 1-Phase vs. 3-Phase Residential Distribution

United States	Europe
120/240 V	400 Wye/230, 4-wire (Europe)
Single-phase transformers heavily overloaded—25 kVA typical	Less load per home than U.S.
Four homes/transformer fairly typical	3-Phase xfrms >> 1-phase
Fuses are typically expulsion	Residential units in 300–500-kVA range, 5 to 10 radial 3-phase 4-wire secondary feeds, per transformer
	No overload
	Fuses are current-limiting
	100 to 200 dwellings per transformer

modular in design, so that manufacturing economies of scale are driving their costs down. Generally, distributed resources are small in size, ranging from less than 1 kW to a few hundred kW. The practical size limit for generators on the distribution system is in the area of around 35 MW.

The justification for introducing these newer technologies include the renewable resource aspect and lower environmental impact along with niche opportunities in particular regions when one or more of these technologies might excel. It is claimed that more DR means less T&D investment. Without storage, many DR technologies provide an additional energy source but no demand or investment savings. Then too improved reliability is often touted as a benefit, but this needs to be properly evaluated in the context of what technology is being discussed. Without careful engineering, a particular MW level of DR penetration can adversely affect the distribution system.

Distribution designs are based on a number of principles that can be upset by DR including:

- Most distribution circuits are radial in nature with power flow from the substation to the loads.
- Voltage control with line drop compensation through LTC transformers or voltage regulators presumes a dropoff of load and voltage as one proceeds from the substation and, further, that power flow is from the source side to the load side.
- Most overcurrent protective device selection and coordination is based on higher fault current magnitudes at the substation and declining fault current magnitudes toward the end of the circuit.
- Reclosing intervals of circuit breakers and reclosers and reclosing practice in general is based on reasonable fault clearing times and the expectation that the reclosing device will close into a de-energized line.
- Utility restoration practices are based on having a limited number of known sources controlled by switches and other protective devices with known states (energized or de-energized).
- Harmonics are limited to larger known sources and distributed smaller sources.
- Most 3-phase transformer connections on distribution are grounded-wye grounded-wye.

With the arrival of distribution resources, many of these *normal conditions* now change, including:

- Bidirectional power flow and fault current flow along portions of the circuit.
- Load magnitude dropping off along the feeder and then reaching a step change at the DR location(s) and dropping off beyond that point.
- Fault current profile showing the increase in total fault current due to added generation as well as the bidirectional fault current flows from the DRs depending on fault location.
- Automatic reclosing for utility circuit breakers and reclosers will have to be supervised with some form of voltage check and possibly time delay. An alternative is to use transfer-tripping schemes to assure that the DR is off-line before reclosing takes place.
- Many DR advocates seek a delta-wye connection. Under backfeed conditions, a single-line-to-ground fault on the primary will overstress the surge arresters on the unfaulted phases.
- Photovoltaics and many small wind generators are dc machines that rely on invertors to produce an ac waveform and also produce high harmonic content. Induction-type machines draw reactive power from the power system. The combination introduces both voltage drop and power quality concerns.

IEEE Std 1547-2003, Standard for Interconnecting Distributed Resources with Electric Power Systems, was developed to provide a uniform standard for the interconnection of distributed resources with electric power systems. It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. Follow-on standards projects to Std 1547 are intended to address the different DR technologies and engineering concerns about the interconnection issues.

A logical concern is—at what level of distributed resources does one have to be concerned with some of these potential issues becoming genuine problems? Unfortunately, we don't yet have an answer to that question.

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